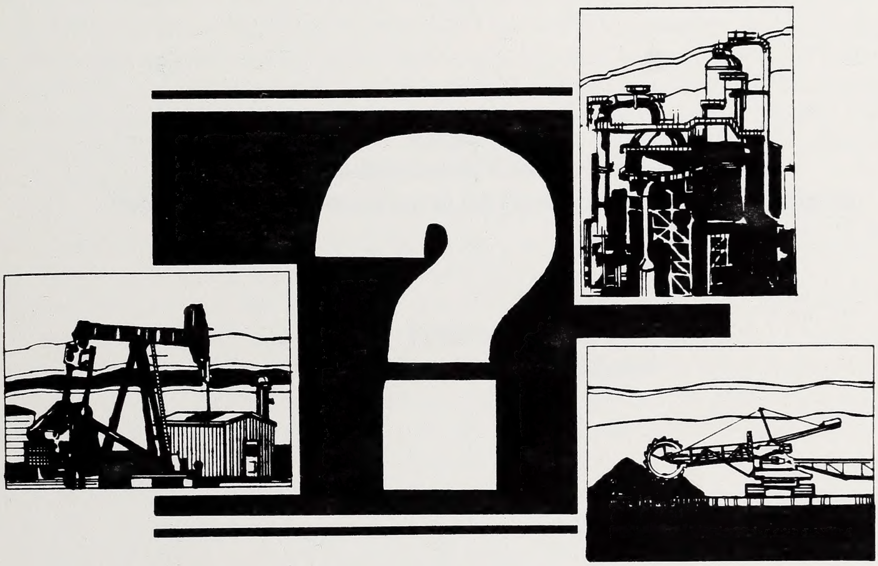
Oil and Gas in Alberta:
An Uncertain Future



A Discussion Paper Prepared for the Alberta Conservation Strategy Project

Oil and Gas in Alberta:

An Uncertain Future

Prepared by
Energy and Non-Renewable Resources Sub-Committee
Public Advisory Committees to the Environment Council of Alberta

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FOREWORD

In late 1985, the Public Advisory Committees to the Environment Council of Alberta began working toward a draft conservation strategy for Alberta. The Public Advisory Committees (PACs), comprising representatives of some 120 non-government organizations, are in many ways an ideal organization for developing a strategy that should touch the lives of all Albertans. The PACs bring together many diverse viewpoints, we are non-partisan, and we have members from across the province. Since the early days of the project, we have welcomed non-PAC participants, and have been delighted to receive the contributions of civil servants, industry spokespeople, academics, and the general public.

We have made progress since 1985: the *Prospectus for an Alberta Conservation Strategy* has been published and many meetings and workshops have been held. The principle of a conservation strategy increasingly has been endorsed by Albertans, and Alberta has been recognized across Canada as a leader in conservation strategy development. There have been important related events. For example, in September of 1987, every environment minister in Canada endorsed the final report of the National Task Force on Environment and Economy, which recommended that conservation strategies be in place in every province and territory by 1992. This same report was endorsed by the First Ministers at their November, 1987 meeting.

We will have a conservation strategy for Alberta, we hope by 1990. Our work continues in the expectation that all those who are interested will have a chance to contribute to the project, through public hearings or some other public participation process.

Since the publication of the *Prospectus*, the PACs have concentrated on preparing sectoral discussion papers. The Conservation Strategy Steering Committee determined early on to produce background papers on relevant sectors, such as agriculture, fish and wildlife, tourism, oil and gas, and others. These discussion papers look at the issues within each sector, but, more importantly, they investigate the interaction of each sector with the others. Their preparation has involved consulting with a wide range of interest groups — a conservation strategy principle in action — which has proven fruitful in developing ideas about the ultimate conservation strategy. These discussion papers will be used as background information for drafting a conservation strategy document and, perhaps, in the future, in public hearings on the draft conservation strategy. This report is one in the series of discussion papers.

Because there are as many opinions on our best future direction as there are Albertans, we welcome comments. The conservation strategy will be only as good as the work that goes into preparing it. Please address any comments on this discussion paper or others in the series to the Environment Council of Alberta at the address given on the page opposite. I would also encourage you to make your opinions known at public hearings or other events as they are held. Let's treat Alberta as if we plan to stay!

Jean Snyder

Jean Snyder
Chairperson
Conservation Strategy Steering Committee
Public Advisory Committees to the Environment Council of Alberta

ABOUT THIS DISCUSSION PAPER

The development of Alberta's oil and gas resources has had a profound effect on economic, environmental and social conditions in the province. The revenues provided by these resources have led to strong economic growth and the high standard of living enjoyed in Alberta. Economic well-being brought increased opportunities to enjoy the province's cultural, social and natural wealth, to participate in outdoor recreational activities, and to appreciate our clean air, water and scenic beauty. Greater appreciation of these attributes has led to increased concern about the environmental impacts of oil and gas development and the need for development that is compatible with environmental protection. How should Alberta's oil and gas resources be used in the interests of developing an economy that is environmentally sound as well as economically sustainable? This paper is intended to stimulate discussion of the ideas and issues embodied in that question.

ACKNOWLEDGEMENTS

The Energy and Non-Renewable Resources Sub-Committee is pleased to provide this paper as part of the Alberta Conservation Strategy Project. Oil and gas development is a mainstay of the Alberta economy and its importance is reflected in the time and effort that many individuals spent in preparing this Discussion Paper. Members of the Sub-Committee and the Oil and Gas Sector Committee all had a hand in the preparation, review and redrafting of this paper. A special thanks must be extended to Betty Hunter, the Oil and Gas Sector Leader, who has been a keen proponent of this paper since the beginning and was responsible for gently nudging it to completion.

The Sub-Committee and the Oil and Gas Sector members drew upon their personal experience and knowledge as well as that of the many speakers who shared their views and ideas at regular Sub-Committee meetings. These people are too numerous to mention but individuals may recognize their contributions to the words of this paper.

Many other people were drawn into the report preparation process from time to time. The Sub-Committee would like to thank the Canadian Petroleum Association for its contribution to two chapters to the report, and Vern Millard, former Chairman of the Energy Resources Conservation Board for his work on the Chapter "Managing Resources for the Future".

The paper has been much improved by the critical reviews, constructive comments, and helpful suggestions provided by reviewers in The Energy Resources Conservation Board, Alberta Energy, Alberta Environment, Alberta Forestry, Lands and Wildlife, and Alberta Agriculture.

The paper could not have been written without the help of John Lilley, who assisted with the research and writing, and other staff of the Environment Council who assisted with reviews, typing and editing.

Executive Summary

Oil and Gas in Alberta: An Uncertain Future

Much of the economic and population growth in Alberta over the last four decades is a result of economic activity and employment opportunities created directly or indirectly by the petroleum industry.

Alberta is fortunate in the extent of its hydrocarbon resources. It contains 76 percent of Canada's known reserves of conventional oil, 100 percent of its oil sands and bitumen, 94 percent of the natural gas and 68 percent of the country's coal. As a result, Alberta is a major supplier of oil and gas. Forty-two percent of the oil and gas produced in 1987 went to other parts of Canada, 35 percent was exported and 23 percent was used within Alberta.

Dependence on oil and gas development has created an economy that is vulnerable to swings in energy markets and prices. In 1985, government revenues from the oil and gas industry totalled $5 billion and represented 46 percent of the provincial government's revenues. Following a global downturn in oil prices, they dropped to $2.7 billion or 28 percent of overall revenues in 1988.

A distinction must be made among the different grades of oil before the supply and demand outlook can be discussed. Conventional oil includes light and medium oils which can be recovered using traditional pumping techniques. Recovery of heavy oil requires specialized treatment such as steam injection to make the oil less viscous and enable it to be pumped. Oil sands contain deposits of very thick oil that are mined and processed into a synthetic crude oil.

About 70 percent of the conventional oil discovered in Alberta has already been produced. Annual additions to reserves have been declining, and within 35 years, production is expected to drop to less than 10 percent of present levels. While enhanced oil recovery techniques may result in extraction of more oil from proven reserves, development of new technologies is important as are higher oil prices.

Production of heavy oil and synthetic crude is projected to increase, offsetting the decline in conventional oil production. Greater production of non-conventional oil will require an increase in oil prices or technological advances to make developments economically attractive. With current technology and anticipated economic conditions, only a small fraction of the potential reserves in the oil sands areas will be exploited.

In a situation similar to conventional oil reserves, about 45 percent of the initial established reserves of natural gas has been produced and production is expected to peak in the next decade. At the present rate of use, the potential reserves of gas would last about 50 years.

If all the reserves could be developed, it is unlikely that Alberta would run short of oil. But the availability of reserves is, by itself, insufficient to guarantee production. The questions that face oil and gas development relate not so much to the availability of these resources (although shifts from one energy source to another may be required) as they do to the financial, environmental, and social costs and benefits of future developments.

Albertans face a challenge in managing oil and gas resources over the long-term and in planning for the time when the economic and energy contributions made by oil and gas decline. No plan would be complete without considering the uncertainties of price, supply and demand which so greatly affect the future. Development of Alberta's oil and gas resources should ensure that

future generations have access to competetively-priced energy sources, and that our use of non-renewable resources leaves no debts, economic or environmental, for the future.

Growth in energy demand could be drastically lower than conventional projections indicate if modern, high-efficiency energy technologies are brought into widespread use. A reduction in demand could result in excess production capacity and threaten price stability.

Alberta's exports of natural gas to the United States are increasing dramatically. But one must question the long-term benefit of additional exports. Future sources of supply will be more expensive to develop and produce than present supplies. The result will be more expensive energy, perhaps placing Alberta at a competitive disadvantage with other suppliers of oil and gas.

Because of the extent of oil and gas resources in Alberta, exploration and development activities have touched most parts of the natural environment and the lives of most Albertans. The oil and gas industry is closely regulated by government departments and agencies, most notably Alberta Environment, Alberta Energy, Alberta Forestry, Lands and Wildlife, and the Energy Resources Conservation Board (ERCB).

In recent years, the industry has taken major steps to reduce the negative impacts of its operations. Some actions were to conform with government regulations but others were taken in the recognition that companies must incorporate environmental planning into their decison-making process. Agencies such as Alberta Environment and the ERCB encourage the industry to be more responsive to public concerns about health, safety and environmental impacts. Despite the progress, many environmental issues still confront the future of oil and gas development.

Three in particular seem to pose major challenges:

- development of reserves in areas protected for other resource uses or areas of special significance for ecology, recreation or tourism;
- the social, economic and environmental implications of the scale of oil sands development that might be required to offset declining conventional oil production; and
- the growing concern about local, regional and global consequences of emissions of nitrogen oxides, volatile organic compounds, acid-forming precursors and carbon dioxide.

Policies and programs developed by governments at all levels as well as the actions of individuals in response to real or perceived problems connected with the use of fossil fuels could have major consequences on world energy markets and prices, on the development of Alberta's energy resources and on the economics of the energy industry. Environmental and social concerns and economic feasiblity, not resource availability, could be the main factors affecting Alberta's energy future.

Albertans are faced with tough decisions about their energy future and the place of fossil fuels in that future. Many actions might be taken. In most cases, it is not a matter of one action or another but of developing a long-term strategy that considers many options. A clear policy framework is needed within which discussions and negotiations aimed at reducing the conflicts over oil and gas developments can take place.

How Albertans want to develop their energy resources is a matter that deserves serious public discussion. Although enormous uncertainties arise in attempting to plan for the future, appropriate mechanisms or institutions must be in place to involve government, industry and the public in making the necessary decisions. A process is needed to convert Albertans' wishes and aspirations for the future into a comprehensive energy policy.

Planning for this future should begin now.

Contents

Chapter One

Introduction

The products and by-products of crude oil and natural gas processing are virtually unlimited. Gasoline, diesel and jet fuels, waxes, paints, shampoos, insecticides, weed killers, fertilizers, plastics, rubber, fabrics, cleaning solvents, and anesthetics are all made totally or partly from hydrocarbons. The use of hydrocarbons affects every aspect of our lives. The demand for them fuels the search for oil and gas and development of the resources.

The demand for Alberta's oil and gas resources has been a major factor behind the province's economic growth in recent decades. But Albertans know the frailties of an economy heavily dependent on a single resource-based industry. Albertans have experienced the effects of a rapid increase in petroleum prices. Then they suffered through an economic recession when petroleum prices declined dramatically.

Albertans have seen many booms and busts in petroleum resource development as a result of changes in supply and demand around the world. And the exploitation of Alberta's oil and gas reserves has irreversibly changed the face of the province.

In the prudent management of their non-renewable resources, Albertans need to plan for the vagaries of energy prices and resource availability. This need has been recognized by the provincial government through establishment of the Alberta Heritage Savings Trust Fund. This Fund was established in 1976 to save for the future a portion of the revenues from non-renewable resource development and to use some of these revenues to strengthen and diversify the economy to face future challenges. In recent years, under the pressures of declining economic growth, further contributions to the Fund have been suspended and the interest income is now incorporated into Alberta's general revenues.

One of the challenges facing Albertans will be how we manage our oil and gas resources over the long term. These resources are finite. Although it is unlikely that every drop will be extracted, at some time the benefits provided by this exploitation will draw to an end. A key factor in maintaining a healthy economic future and good quality of life for Albertans will be our ability to plan for the time when the economic and energy contributions made by oil and gas decline to a relatively small proportion of Alberta's needs. One essential aspect of a long-range strategy is wise investment of capital generated from the exploitation of non-renewable resources to encourage development of future energy sources. Another is maximum efficiency in the use of present resources.

The Public Advisory Committees to the Environment Council of Alberta have adopted the following objective concerning non-renewable resources:

> *"To use and manage our non-renewable resources in the interests of developing a long term sustainable economy for Albertans".* (Public Advisory Committees 1987: 63).

Alberta's hydrocarbon resources are primary energy sources for Alberta and the rest of Canada and contribute to an important export market that has been growing in recent years. This paper discusses Alberta's oil and

gas resources, their development and economic significance, and the supply of and demand for these resources. Oil and gas reserves cannot be developed without interactions with other resources and resource users. These impacts are discussed, as well as the legislative framework within which development occurs. The paper concludes with a section on managing Alberta's non-renewable energy resources for the future and some ideas for an energy strategy. These sections raise questions instead of trying to provide all the answers. They are intended to stimulate discussion about the problems and opportunities that face Albertans as we move toward declining oil and gas reserves. Technical terms appearing in italics in the text are defined in the glossary at the end of this paper.

Chapter Two

The History of Oil and Gas Development in Alberta

The Formation of Oil and Gas

Oil and gas are found in rocks formed of sediments laid down in ancient seas. Oil and gas probably began as the remains of countless tiny plants and animals that lived in the ancient seas or washed down into them with mud and silt from the surrounding land. These remains accumulated in layers on the sea bottom and were incorporated over time into layers of sedimentary rocks.

The organic matter gradually changed into liquid and gaseous *hydrocarbons*. As liquids, hydrocarbons occur in a wide range of *viscosities* from *light crude oils*, with a consistency like motor oil, to asphaltic materials such as those found in oil sands. The different permeabilities of sedimentary rocks allow oil and gas to move relatively easily through some layers and not so easily through others. Because gas is lighter than oil and oil lighter than water, oil and gas travel upward through the sedimentary rocks until stopped by a dense, non-porous barrier. Here the migrating oil and gas accumulate. Formations of rock which contain these accumulations are called reservoirs. The most common reservoir rocks are sandstones, conglomerates and limestone.

With an understanding of the distribution and character of the sedimentary rocks underlying Alberta, it is possible to map the locations of the ancient seas, shorelines and continental land masses that played a role in the accumulation of oil and gas. Nevertheless, the distribution of oil and gas in these three-dimensional underground formations remains extremely difficult to determine and exploit. Dry holes usually outnumber successful wells by about two to one and gas may be found where oil was expected. Occasionally big finds are made and a new gas or oil "field" hits the news, but such finds are becoming increasingly rare.

Even "big" finds in Alberta can not be compared with the huge reservoirs and high production rates possible in other parts of the world. Reserves, particularly in the Middle East, but also in Africa, South America and the Far East are plentiful. This oil and gas is relatively cheap and easy to produce. The implications for this disparity in the worldwide distribution of oil and gas reserves are discussed in Chapters 7 and 8.

Conventional Oil and Natural Gas

Although both oil and gas had long been used in various applications, the world's first oil company was incorporated by Canadians in 1854 in southwestern Ontario. The company was intended to produce a variety of products from the local *bitumen* beds. In 1858, the first well drilled specifically to find and produce *crude oil* was successfully completed in the same area.

In 1870, geological surveys in Alberta determined the presence of oil and gas in surface seeps about 225 kilometres southwest of Calgary. But it was not until 1890 that

drillers, looking for coal for the Canadian Pacific Railway, struck the reservoirs that led to the first commercial gas well in Alberta. The well was used to provide gas for Medicine Hat.

Western Canada's first producing oil well was successfully completed in 1902 in the area now known as Waterton Lakes National Park. However, during the first decade and a half of the 1900s, natural gas became more commonly used than oil. Calgary had natural gas street lighting by 1909. By 1912, natural gas was being piped 274 kilometres from Bow Island to Calgary.

Oil was to become the more sought-after hydrocarbon. The advent of the automobile and the need for the fuels that oil could provide motivated the search. The road to discovery was very difficult and it was not until 1914 that Western Canada's first oil boom began. The discovery of oil at Turner Valley signalled the beginning of the modern petroleum era in Alberta.

However, the Turner Valley field proved very difficult to develop. Oil was not found in the volumes anticipated. It often came as a very light hydrocarbon, called *condensate*, together with natural gas. Natural gas was considered an annoyance and was flared. Eventually, a well drilled in 1936 to a depth of 2,524 metres revealed large quantities of crude oil, confirming Turner Valley as a major field. Further drilling determined reserves of 79.4 million cubic metres (half a billion barrels) of oil.

By 1946, Canadian consumption had reached 35,140 cubic metres (221,000 barrels) of oil a day, of which 31,800 cubic metres (200,000 barrels) were imported. The Turner Valley field produced about 3,180 cubic metres (20,000 barrels) per day. The rest of Canada's domestic production came from southern Ontario. Under this scenario of supply and demand, millions of dollars were spent on oil exploration in Western Canada. The demand for liquid fuels was so great that companies experimented with manufacturing gasoline from natural gas.

No more major oil fields were found in Alberta until the 1947 Leduc discovery, 33 years after the first successful Turner Valley well. Further drilling provided important evidence that Devonian reef formations such as the one at Leduc could contain oil and gas reservoirs with good potential. This eventually led to drilling and discoveries from central Alberta north to Norman Wells in the Northwest Territories.

In the late 1940s and early 1950s, several other major oil fields were discovered in Alberta, including one at Pembina in 1953. The Pembina field eventually proved that large reservoirs could be found in previously unknown formations.

Between 1959 and 1964, major oil discoveries tapered off and the industry concentrated on developing known reserves. Then, in 1965, a major oil discovery was made at Rainbow Lake. No new major fields were discovered until 1977 when large oil reserves were found in the West Pembina area southwest of Edmonton. About the same time, a new gas field, large enough to rival the reserves of Alberta's biggest established gas fields, was discovered in the Elmworth area near Grande Prairie. These discoveries expanded the industry's horizons.

Heavy Oil

While attention focused on natural gas and *conventional crude oil*, *heavy oil* reserves also were being developed. Deposits were discovered in the Lloydminster area in the 1930s. The main products from these reserves are asphalt for paving roads and making shingles and roofing materials. Some low-grade fuels and lubricants are also produced.

Because Canadian demand for asphalt is seasonal, heavy oil producers have traditionally relied on exports to markets in the United States. Heavy oil currently represents about 10 percent of Canada's total oil production. Interest in heavy oil extraction is increasing and the development of *heavy oil*

upgrading facilities in the Lloydminster area will mean that heavy oil can be processed into a feedstock suitable for use in Canadian refineries.

Oil Sands

Alberta has four major areas of *oil sands* — Peace River, Athabasca, Wabasca and Cold Lake — which underlie more than 70,000 square kilometres (27,000 square miles) of northern Alberta.

The first documentation of oil sands in Alberta was made in 1719 by Henry Kelsey, a manager for the Hudson Bay Company. Their location was recorded on maps by Peter Pond in 1778. The oil sands areas are estimated to contain about 159 billion cubic metres (one trillion barrels) of oil, although none of it is recoverable through conventional wells.

Attempts were made as early as 1906 to extract oil from the sands. Sidney C. Ells of the Canada Department of Mines, spent more than 30 years investigating the possibilities of oil sands development, pursuing both the idea of using oil sands for road surfacing and separating the oil from the sand with a hot water process. Dr. Karl Clark of the Alberta Research Council also investigated recovery of oil from the oil sands. His 1922 report favored the processes suggested by Ells. Hot water separation remained the most popular technique and a variety of experimental plants and commercial ventures were attempted, some successfully, but none on a large scale. Development was hampered by the distance from markets, lack of capital, lack of a cost-effective technology for washing bitumen out of the oil sands and the decline in oil prices as more reserves of conventional oil were discovered.

By the late 1950s, major companies began to take an interest in oil sands mining. But it was not until 1967 that Great Canadian Oil Sands Ltd., now called Suncor, began operation of the first commercial scale oil sands plant in the world. Maximum capacity of this first plant was 10,335 cubic metres (65,000 barrels) per day.

In 1978, the second commercial oil sands plant, Syncrude Canada Ltd., came on stream with a design capacity of 16,377 cubic metres (103,000 barrels) per day. By 1982, an expanded Suncor and the Syncrude plant were responsible for almost 15 percent of Canada's domestic oil production. With planned expansions of both facilities and a third plant proposed in the area, the contribution of synthetic crude oil to Canada's oil production could increase substantially in the next decade.

The oil sands are also being tapped by *in situ* methods, usually by injecting steam or hot water into the formation to make the oil less viscous. The oil is extracted from another nearby well. This technology is used in oil sands developments in the Cold Lake and Peace River areas.

Chapter Three

Supply and Demand

Because hydrocarbons, especially oil, are relatively easy to transport, they are traded internationally and moved daily throughout the world. Since prices are determined by production and demand at a world level, oil and gas development in Alberta must be examined from an international perspective as well as from a provincial and national viewpoint.

Alberta serves as Canada's major energy storehouse, with more than 76 percent of the nation's known reserves of conventional light and medium oils, 94 percent of its natural gas, 100 percent of its oil sands and bitumen and 68 percent of its coal reserves (ERCB 1987a). In 1987, 82 percent of Canada's production of conventional oil, 100 percent of bitumen and *synthetic crude oil* production and 89 percent of the natural gas came from Alberta (ERCB 1987a). Of the oil and gas produced in Alberta in 1987, 23 percent was used in the province, and 42 percent in other parts of Canada, while 35 percent was exported (ERCB 1987a).

In 1987, Canada produced about 248,000 cubic metres per day (1,560,000 barrels) of oil and 219 million cubic metres per day (7,753 million cubic feet) of natural gas. This is only about two percent of the free world's daily primary energy consumption, calculated at 16.3 million cubic metres (102 million barrels) of oil. This figure excludes the centrally-planned economies of China and the USSR (Arthur Andersen & Co. 1988a and 1988b).

As a small player on the world scene, Canada has little influence on the international supply-demand equation. However, Canada does have considerable influence on supply and demand within its own boundaries and on the export of Alberta's oil and gas. National and provincial energy policies have important impacts on demand for and production of Alberta's hydrocarbons. Oil and gas development activities in Alberta can vary in response to changes or anticipated changes in world energy prices and as a result of market forces or government policies.

The situation is complicated by the range of hydrocarbon fuels available, differences in reserves of various hydrocarbons in Alberta, differences in cost of production, the degree of fuel source substitution possible and preferential demand for specific hydrocarbons for certain applications. Not all hydrocarbons are available in similar quantities, or at similar costs; nor are demands similar or even necessarily moving in the same direction. The management of Alberta's hydrocarbon resources thus presents a very complicated and ever-changing picture.

On a per capita basis, Canadians consume more energy than anyone else in the world. This stems partly from the cold climate and long transportation distances. More significantly, this reflects wasteful use resulting from Canada's ample energy resources and relatively low prices.

Even so, Canada's energy consumption patterns changed markedly between 1973 and 1987. The total primary energy consumption in tonnes of oil equivalent per $1000 of gross domestic product (GDP) dropped from 0.89 in 1973 to 0.73 in 1987 (Fig. 1). As noted by Arthur Andersen & Co. (1988b): "The recent decline in oil prices has not impeded

the process of reducing energy intensity. There is no major OECD economy in which the 1987 ratios of energy/GDP or oil/GDP are greater than they were in 1985. Improved efficiency and a structural change away from 'smokestack industries' are sustaining this trend towards 'energy deintensification,' especially in Japan. Worldwide, conservation has turned out to be the most important incremental energy 'source' of all." (p.22).

Proportionately, the drop in oil consumption is even more startling: from 0.39 tonnes of oil per $1000 of GDP in 1973 to 0.23 in 1987 (Fig. 2). Other data show that between 1975 and 1986, the share of Canada's energy needs supplied by oil dropped from 54 percent to 35 percent (Fig. 3). This reflects increased efficiency in the use of refined petroleum products, a general shift away from oil as the primary energy source and an increase in the use of renewable energy sources, nuclear power, coal and hydroelectricity.

Changes in Canadian energy use patterns have been conditioned by development of alternative energy sources and by government policies that emphasized substitution of gas for oil rather than conservation in response to the 1973 and 1978 "oil crises." As a result, on a percentage basis, the decrease in Canada's overall energy consumption has lagged behind other OECD (Organization for Economic Co-operation and Development) countries, although reductions in oil consumption *per se* compare favorably.

Almost all of Alberta's energy requirements are supplied from its own resources, primarily hydrocarbons. In 1987, conventional oil resources supplied 23 percent of Alberta's end-use requirements; bitumen, 25 percent; natural gas, 37 percent; coal, 14 percent; and hydroelectricity, one percent (ERCB 1987a). The end use requirements were divided among the economic sectors as follows: industrial, 40 percent; transportation, 28 percent; residential, 18 percent; and commercial, 14 percent.

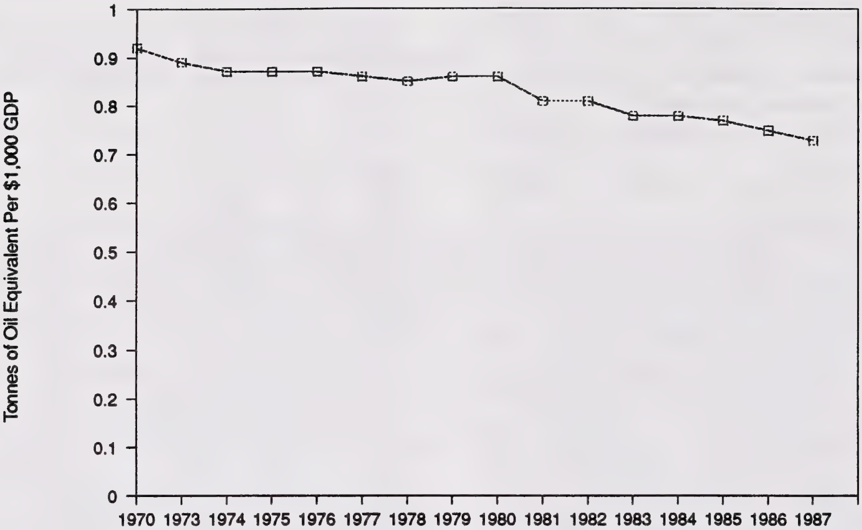
The end-use requirements, as well as the energy resources used to meet them, are changing. Residential and commercial use of energy in Alberta has remained constant since the beginning of the decade while provincial transportation requirements have declined since 1981 (ERCB 1986b). This reflects improvements in energy efficiency. Although conservation efforts may not remain as intense as during the late 1970s because of lower world oil prices, the ERCB expects that longer-term improvements in energy efficiency will continue. As a result, total residential/commercial energy requirements are forecast to increase at one-quarter of the rate that the population is growing. Transportation requirements are expected to increase at about the same rate as the population (ERCB 1986b).

In contrast to the levelling off in other sectors, energy demanded by Alberta's industrial sector has grown to consume almost 40 percent of the total (ERCB 1987a). By 2010, industrial requirements are expected to more than double 1986 levels, representing more than 50 percent of total secondary energy needs in Alberta (ERCB 1986b).

This reflects a trend towards processing more of Alberta's raw energy resources within the province instead of shipping crude oil and natural gas to markets. This includes the refining of crude oil and bitumen to produce petroleum products, processing of natural gas and natural gas liquids, manufacturing of petrochemicals and upgrading of bitumen (ERCB 1986a). In particular, projected growth in natural gas requirements for production of synthetic oil dominates increasing energy requirements. In 2010, conventional crude oil is expected to account for 14 percent of Alberta's primary energy resource requirements; bitumen, 38 percent; natural gas and natural gas liquids, 35 percent; coal, 12.5 percent; and hydroelectricity and wood, less than one percent (ERCB 1986c).

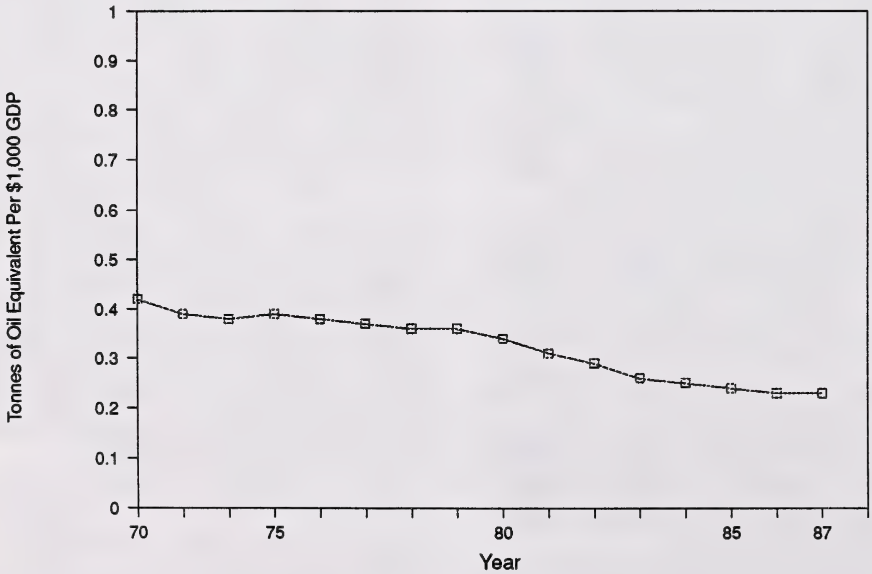
The following discussion provides a more detailed picture of the situation at the end of 1987 and possible developments for Alberta's conventional oil, heavy oil, oil sands and natural gas resources. Alberta's sulphur

Figure 1. Energy Use in Relation to Output



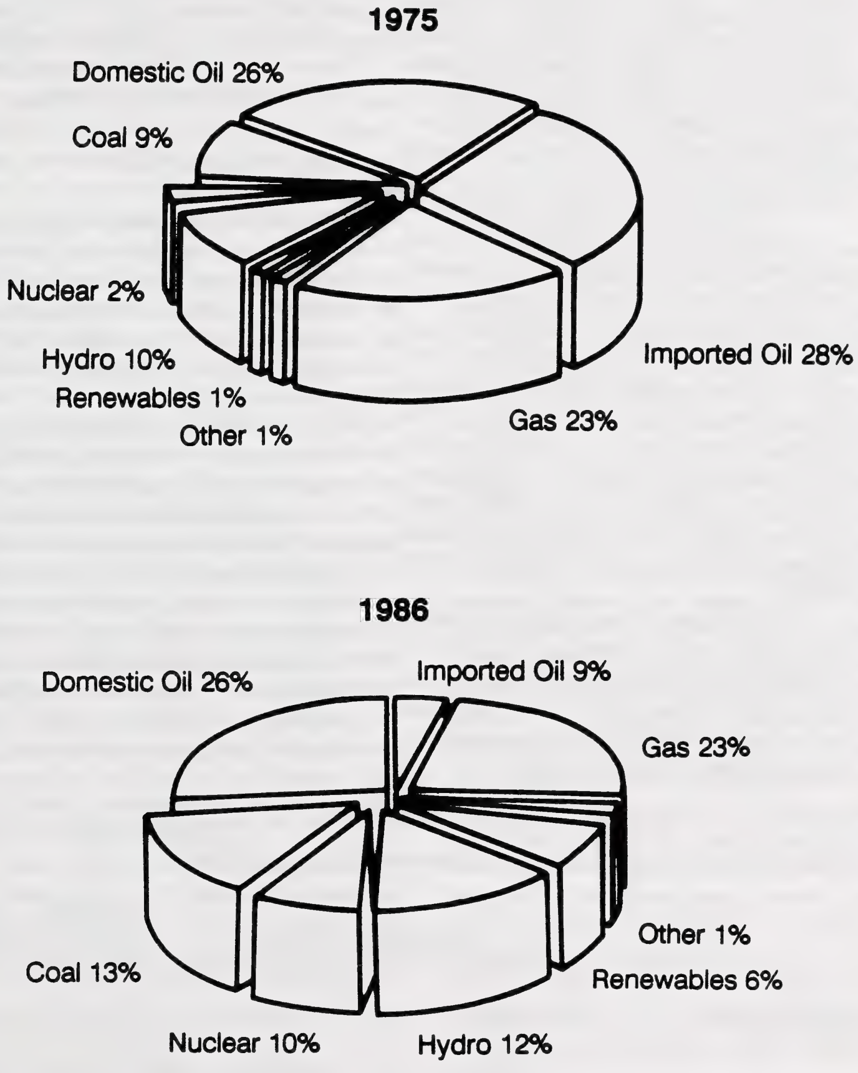
Source: Arthur Andersen & Co. 1988a

Figure 2. Oil Use in Relation to Output



Source: Arthur Andersen & Co. 1988a

Figure 3. Shifts in Canadian Energy Sources



Source: Energy, Mines and Resources 1988

resources are also discussed because of the close ties between hydrocarbons and sulphur production.

The volume of oil and condensate produced in Alberta over the past decade ranged from a high of just over 81 million cubic metres in 1979 to a low of 68 million cubic metres in 1982 (ERCB 1987b). The amount of oil used in Alberta remained relatively steady between 1977 and 1986 while shipments to Eastern Canada decreased and shipments to the United States increased.

In 1987, Alberta produced 212,600 cubic metres of crude oil (1.3 million barrels) per day or about 77.6 million cubic metres (488 million barrels) for the year. Alberta use accounted for 17.7 million cubic metres (111 million barrels) and 26.4 million cubic metres (166 million barrels) were exported to the United States. Except for 780,000 cubic metres (4.9 million barrels) delivered offshore, the remainder, 32.7 million cubic metres per day (206 million barrels), was destined for various parts of Canada (ERCB 1987b).

Conventional oil accounted for about 55.2 million cubic metres of the total oil production and bitumen and synthetic crude for about 6.7 million and 10.5 million cubic metres respectively. The remainder consisted of condensates and *pentanes plus*.

The value of oil production in Alberta rose fairly steadily from $4.1 billion in 1977 to $15.2 billion in 1985 before plummeting almost 50 percent to $8 billion in 1986. It recovered slightly to $10 billion in 1987 but dropped again to $7.7 billion in 1988 (Alberta Treasury 1989). These changes were greatly influenced by world oil prices.

Conventional Oil

Because of the myriad ever-changing variables, it is difficult to estimate accurately how much oil Alberta has left and how long production will last. Oil reserves can be measured only by complex calculations which depend on the state of the technology for exploiting the reserves.

One measure of the extent of oil and gas reserves is the "life index" which is the ratio of the *remaining established reserves* to the current annual production rate. This is therefore an indication of the number of years the established reserves would last at the current rate of production. The life index for 1987 for Alberta's conventional crude oil is the ratio of the established reserves of 614 million cubic metres (3863 million barrels) to the production rate of 55 million cubic metres (347 million barrels) per year. This works out to a

Table 1. Alberta's Energy Resources: Reserve History to End 1987

	Established Reserves			Estimated Future Additions	Total Available For Future
	Initial	Produced	Remaining		
Conventional Oil (10^6 m^3)	2195	1582	614	454	1068
Bitumen & Synthetic (10^6 m^3)	728	157	573	48370	48843
Natural Gas (10^{12} m^3)	3.03	1.38	1.65	1.72	3.37

Source: ERCB 1987c

relatively short 11.2 years. This doesn't mean Alberta will run out of conventional oil in 11 years; new reserves may be added and production rates will decline as reserves are drawn down. Nevertheless, the "life index" is a convenient measure of the current state of conventional oil reserves.

Although oil discoveries continue to be made, they are more modest than in the early years. More than 70 percent of all the conventional oil discovered to date in Alberta has been produced. Alberta's reserves of conventional oil continued to be drawn down in 1987, with production exceeding additions to the *established reserves*, as it has done for eight of the last 10 years. In 1987, remaining established reserves were estimated at 614 million cubic metres (3868 million barrels), 77 percent of the total reserves in Canada (ERCB 1987c). In addition, an estimated 454 million cubic metres (2860 million barrels) could ultimately be added to these reserves (Table 1) through extensions and revisions of existing pools and addition of new pools. Oil delivery capacity declines as wells become less productive. In 1985, production capacity was 174,600 cubic metres (1.1 million barrels) per day but by 1988 it had declined to about 142,860 cubic metres (0.9 million barrels) per day. Conventional oil production is forecast to be less than half the current levels by 2000 (ERCB 1987a) and only one third of the 1985 rate by 2010 (ERCB 1986b).

Some wells have naturally high rates of production, created by rock characteristics, formation pressures, and the volume and type of hydrocarbons. A large majority of wells in Alberta, however, have had their production capability improved through stimulation of the producing formation by chemical or physical means. Pressure maintenance by water injection (secondary recovery) is probably the most common technique. Two other common means are: acidizing — acids are injected to dissolve portions of the formations; and 'fracing' — the formation is fractured by high pressure injection of fluids and the cracks propped open by injecting sand or other hard granular substances.

Even with best available technology, only a minor portion of the oil in a reservoir can be recovered. That amount depends on many factors, including the quality of the reservoir, the viscosity of the oil and the ability of natural forces such as water to drive the oil to producing wells. The average recovery rate for Alberta pools of conventional crude is about 22 percent of the reservoir volume (Alberta Energy 1987).

Recovery can be increased by injecting fluids into the reservoir to push the oil to the producing wells. The most common enhanced oil recovery method is water flooding. Water is injected into the formation to force oil toward the producing well bore. Because of its relatively low cost, water flooding is used 10 times as often as other methods. Enhanced oil recovery techniques can increase the average recovery rate to about 28 percent (ERCB 1986a). At the end of 1987, a total of 739 projects in Alberta were using enhanced recovery techniques, mostly water flood (ERCB 1987a). Under the present low price for oil, many larger scale and capital intensive enhanced oil recovery projects did not proceed. The industry in 1987 generally attempted to improve productivity through small modifications to existing operations.

Miscible drives are also being used more often to enhance oil production. In this method, hydrocarbon solvents or gases, such as liquified petroleum gases, natural gas or carbon dioxide, or a mixture of these, are injected into the reservoir to displace the oil. Some oil industry observers estimate that these techniques could increase the average recovery rate to about 40 percent of reservoir volume.

The conventional oil left in the ground, unrecoverable with today's technology and economic factors, presents a challenge for researchers. The Alberta government, under the Alberta Oil Sands Technology and Research Authority, provides support for investigations into various enhanced oil recovery

techniques. Federal and provincial governments also encourage enhanced recovery activities by favorable oil royalty and tax provisions.

While new technologies are important, price is probably the most important factor determining exploration and development activity and the viability of producing oil from known reserves. When prices rise, it becomes profitable to implement enhanced recovery technologies and increase recovery rates. Some oil industry observers predict that an additional 300 million to 475 million cubic metres (1890 million to 2992 million barrels) of oil could be recoverable if advanced recovery processes were widely used in Canada's oil fields (Alberta Energy 1987). However, the cost of optimizing production must be carefully balanced against the value of the oil and gas produced. There remain billions of cubic metres of crude oil reserves that cannot be exploited economically with today's technology.

An increase in recovery rates will be an important component of any provincial energy strategy. By increasing recovery levels and encouraging development of reserves that are presently uneconomical, advances in enhanced oil recovery technology could retard the decline in Alberta's reserve/production ratio for conventional oil.

Heavy Oil and Oil Sands

The heavy oil fields surrounding Lloydminster contain millions of cubic metres of oil recoverable with current technology. Yet the development of these reserves has been hampered by the marginal economics of recovery processes and by the difficulty of marketing and moving heavy oil. Primary recovery rates average only about six percent, although pilot thermal recovery projects have indicated that recovery rates can be increased to between 25 and 40 percent.

About 50 million cubic metres (315 million barrels) of heavy oil are recoverable by conventional pumping technology. Discovery of new pools, improved understanding of existing reserves and economic and technical improvements may eventually add another 165 million cubic metres to the existing established reserves (Mink 1988).

With the development of upgrading facilities, it will be possible to process heavy oil into a feedstock for Canadian refineries. Development of upgrading facilities and the associated access to new markets could create the economic atmosphere in which more expensive recovery techniques might be used to increase recovery of the heavy oil.

Bitumen recovery requires special processes. These include surface mining, separation and upgrading. Steaming or similar treatment is needed for wells. Bitumen contains about 10 percent hydrogen, ranking it between medium crude oil, which has 13 percent hydrogen, and subbituminous coal, which has six percent hydrogen (McRory 1982). Conventional refineries are designed to operate on liquid hydrocarbons such as conventional oil which have a higher hydrogen to carbon ratio than bitumen. To make bitumen acceptable in these refineries, the hydrogen to carbon ratio must be improved, either by removing carbon or adding hydrogen. Existing commercial oil sands operations usually reduce the carbon content through coking to produce synthetic crude oil, although hydrogen addition, called hydrocracking, is part of present expansion programs.

Production from Alberta's oil sands increased in 1987, largely as a result of continued development of *in situ* projects in the Cold Lake area and higher synthetic crude oil production at the Suncor and Syncrude plants. The production of crude bitumen from *in situ* plants totalled 6.1 million cubic metres, more than double the 1985 production and about 15 times the 1977 production (ERCB 1987b). Production of synthetic crude oil totalled 105 million cubic metres. Production of oil from heavy oil and oil sands is projected to continue to increase, offsetting the decline in production of conventional oil.

By 2000, bitumen production is expected to triple 1980 levels. Production of synthetic crude oil is expected to double (ERCB 1987a). However, this oil is more costly to produce than conventional oil. Growth in production will depend on the net return to project operators, which is influenced by factors such as oil prices, changes in technology that reduce production costs, environmental concerns, and government fiscal policies.

Oil sands development has proceeded slowly because new technology had to be developed and costs are very high. Indeed, development became economically viable only with the higher oil prices that occurred in the 1970s. Development of bitumen production capacity is in a very early stage. To date, less than 0.3 percent of the *ultimate potential reserves* have been produced. The 1987 life index for bitumen and synthetic oil from oil sands was about 27 years, based on remaining established reserves of 573 million cubic metres and annual production of 21.2 million cubic metres. But based on ultimate potential reserves, the life index becomes more than 2000 years. This life index will be reduced substantially as production increases following expansion of the present plants or new plants coming on stream.

During the late 1970s, with high and increasing world oil prices and greater demand, it was projected that a new synthetic crude oil plant would come on stream every four or five years. The decline in oil prices changed that outlook. To date, increases in synthetic crude oil production have been accomplished only through expansions of the two operating plants. Incremental increases in production take advantage of improvements in technology to increase overall efficiencies, make use of the cash flow from the existing operations to fund the expansion and avoid the large, up-front costs of a new facility. For example, a series of expansions at Syncrude will increase production to about 39,000 cubic metres per day. At the same time, an increase in bitumen recovery to about 93 percent, up from 85 percent in 1981, is anticipated along with synthetic oil yields of 93 percent from the bitumen. As well, sulphur emissions and water use will decrease and energy efficiency will improve. Overall operating costs are expected to drop from the current rate of $94 per cubic metre to $82 per cubic metre of synthetic crude oil production (Houlihan and Evans 1988).

A similar situation exists for Alberta's *in situ* projects. Numerous experimental operations are under way in Alberta's heavy oil deposits. Eleven commercial projects have also been approved (Houlihan and Evans 1988) although not all are in operation. Others have been put on hold until oil prices become firmer. Some operations have been limited to incremental expansions instead of larger, more costly projects.

Nevertheless, the long-term future for bitumen production is favorable because of the combination of massive reserves, the demonstration of technical viability by currently operating projects and the increase in oil prices that should occur due to the growing scarcity of the world's oil supplies over the long term. Furthermore, the potential for growth is enormous due to the extensive area of resources not included in reserve estimates because viable recovery techniques have not been demonstrated. With a strong demand and favorable prices, the ERCB expects that technology will be developed and the potential reserves of 48,843 million cubic metres (Table 1) will be realized.

The key to a smooth transition from the production of conventional oil to production of Alberta's bitumen and heavy oil reserves is a steady rise in oil prices.

Natural Gas

In 1987, Alberta delivered just over 67 billion cubic metres of natural gas. Of this, 14.5 billion cubic metres were used in Alberta, 25.8 billion were exported to other parts of Canada, and 25 billion were exported to the United States (ERCB 1987b). (Due to

revisions and rounding in the data, these figures do not add up).

Even though deliveries increased about eight percent in 1987 over 1986 primarily due to increased exports to the United States, production remained substantially less than could be achieved with expanded markets. The industry is operating at below developed wellhead capacity. That situation should change during the next decade, with Alberta's natural gas production continuing as a dominant energy source well into the next century. Despite anticipated new gas discoveries, production capacity is expected to peak in the late 1990s (ERCB 1988a).

Preliminary figures show that the value of natural gas production in Alberta in 1988 totalled $4.4 billion, substantially below the $7.3 billion produced in 1984 despite a 24 percent increase in sales volume (Alberta Treasury 1989). The decline in revenues was due to a drop in per unit price exacerbated by a strong Canadian dollar.

No additions to gas reserves were recorded in 1987. Production has now exceeded reserve additions for all years 1983 to 1987. The decrease in established reserves reflects a drop in drilling activity and a focus on oil exploration. The decline in natural gas exploration and development activities is due to reduced gas prices and the large volumes of natural gas that remain shut in because of present market conditions.

Somewhat similar to the situation with conventional oil reserves, a significant portion of the *initial established reserves* of natural gas has been produced — about 45 percent. After accounting for the 1987 production of 68 billion cubic metres, the remaining established gas reserves in Alberta decreased to about 1,650 billion cubic metres. However, ultimate potential reserves could add 1,720 billion cubic metres to the energy available from natural gas in Alberta (Table 1).

While the production of oil and gas has been estimated by the ERCB to follow a pattern similar to Figures 4 and 5, reality seldom matches projections of a smooth transition from one energy source to another. A quick review of the past 10 years, or even the past 10 months, is enough to remind anyone that no projection can be completely accurate. What is certain is that as long as Alberta's economy remains heavily dependent on revenues from the development of oil and gas reserves, the province will continue to experience substantial swings in provincial income.

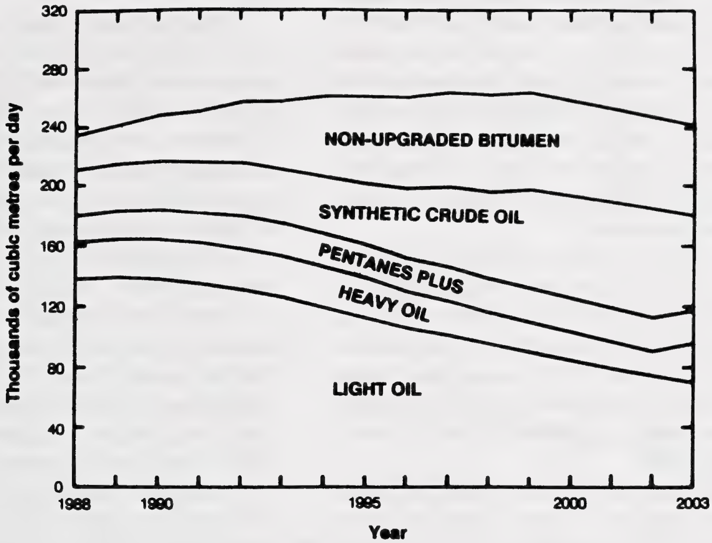
The 1980s have been characterized by a more diverse mixture of energy forms, a trend that is expected to continue. It is anticipated that the economy will become less dependent on oil, more electricity intensive, and generally will be based on a more flexible, more diversified energy system. In developing a conservation strategy for Alberta's oil and gas, one must be aware of the potential impacts of changing circumstances within Alberta as well as nationally and internationally. Alberta's future energy policies should be flexible and capable of responding to changing demand for energy products. These issues are discussed in more detail in Chapters 7 and 8.

Sulphur

World consumption of sulphur totals approximately 55 million tonnes per year. One third to one half comes from workable deposits of elemental and combined forms of sulphur. These deposits, distributed worldwide, contain 1,000 to 10,000 times current annual consumption. Most of the remainder comes from 'involuntary' production, a byproduct of pollution control requirements on smelters and sour gas and oil plants (EMR 1983), although some sour gas reservoirs are now being developed primarily for their sulphur content.

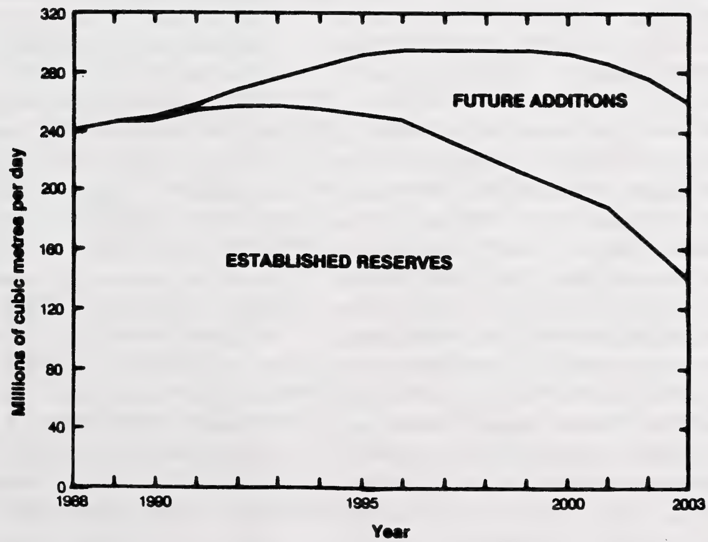
The sulphur produced in Alberta is from the latter source: 99 percent pure, elemental sulphur recovered as a byproduct of tail gas clean up at sour gas processing plants and during processing of oil from Alberta's oil

Figure 4. Crude Oil and Equivalent Supply (1988 - 2003)



Source: ERCB 1988a

Figure 5. Marketable Gas Supply (1988 - 2003)



Source: ERCB 1988a

sands. Proposals are currently before the ERCB to recover sulphur from gas deposits with hydrogen sulphide concentrations of 35 percent or more. They would be developed primarily because of their sulphur content. Major consumers of sulphur or sulphur compounds include the uranium industry, pulp and paper manufacturing, smelting and refining and producers of fertilizer and industrial chemicals.

Although Canada accounts for 13 percent of world production of sulphur, most of it from Alberta, the province consumes only three percent of the total (EMR 1983). Canada is a major exporter of sulphur, accounting for 40 to 50 percent of global export trade (EMR 1983), and has a significant impact on world sulphur prices.

Sulphur production in Alberta increased rapidly beginning in 1966, peaked in 1973 and has declined somewhat since that time (Figure 6). Production has decreased because the new gas wells brought on stream have been mainly sweet gas with a lower sulphur content.

Over the same period (1952-1986), sulphur sales generally increased with some ups and downs (Figure 6). Alberta sulphur sales in 1986 totalled 6.6 million tonnes valued at $683 million (Canadian Petroleum Association 1987a).

The result has been a steady decline in the inventory of sulphur from a peak of more than 20 million tonnes in 1978-79 to about 8.5 million tonnes in 1986 (Figure 6). The large blocks of sulphur that formerly dotted Alberta's landscape are quickly disappearing.

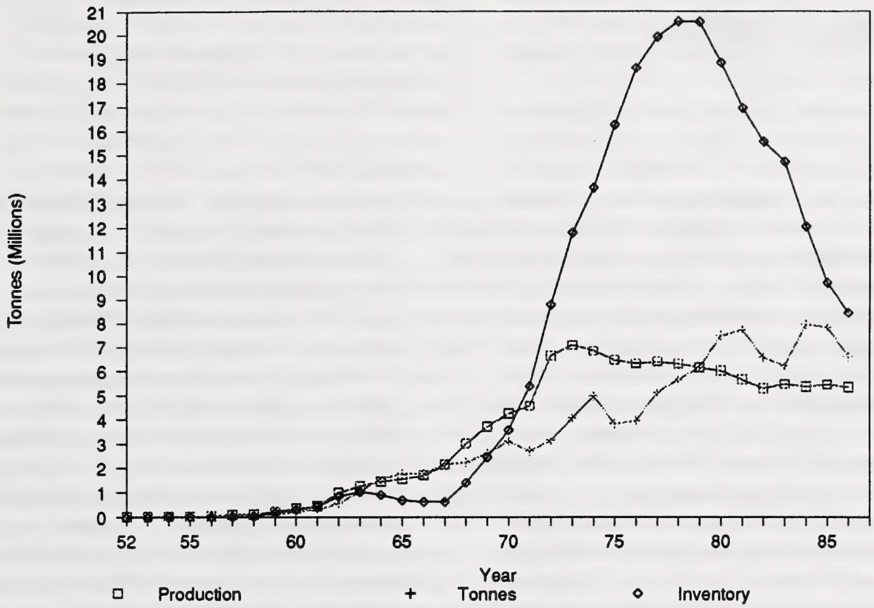
The Energy Resources Conservation Board estimated that the total established sulphur reserves remaining in Alberta at the end of 1987 totalled 102 million tonnes (ERCB 1987c). These estimates include sulphur recoverable from natural gas and from crude bitumen reserves under active development at the approved Suncor and Syncrude projects. In addition, approximately 150 million tonnes of sulphur could be recovered from the remaining established crude bitumen reserves in the surface-mineable area.

After 30 years of growth at a cumulative rate of 5.5 percent per year, world consumption of sulphur peaked at 55.7 million tonnes in 1980. In 1981, demand fell, especially in the western world, where annual demand for elemental sulphur decreased by four million tonnes (EMR 1983). This decline was due to the world-wide recession which affected the industrial demand for sulphuric acid and to lower agricultural prices which resulted in a decreased application of fertilizers. The decrease in demand for Alberta's sulphur was reflected in a significant reduction in the 1982 and 1983 sales (Figure 6). Sales rebounded to a new peak but declined again as a result of another reduction in demand for fertilizers.

At a rate of 55 million tonnes per year, world-wide consumption of sulphur exceeds production by about 1.25 million tonnes per year. This demand is met by withdrawals from stockpiles, mainly those in Alberta (EMR 1983) and demand for Alberta's sulphur continues strong. During the present period of relatively low prices for natural gas, the value added by the recovery of sulphur is sufficient to encourage development of gas reserves with high levels of hydrogen sulphide. Such is the case with a proposed development near Bearberry, Alberta. The estimated hydrogen sulphide content of the reserves is greater than 90 percent. Total sulphur reserves in the area generally known as the Caroline Field are estimated at between 70 and 100 million tonnes. About one third of this amount is believed to be recoverable using present technology (ERCB 1987a) and is included in the estimates of established reserves.

World sales of sulphur are a delicate balance of market share and price between voluntary and involuntary producers. Because sulphur is an essential reagent without competitively-priced substitutes, demand for it has not been greatly affected by changes in price over the range of historical prices (EMR 1983). Because there are abundant supplies of workable sulphur deposits, the largest in-

Figure 6. Alberta Sulphur Production and Sales



Source: Canadian Petroleum Association 1987a

voluntary suppliers — such as Alberta's producers — recognize that their financial return will be maximized if prices are about equal to the average cost of production of the voluntary producers (those who can readily modify production in response to price changes).

Higher prices would cause voluntary production to increase and result in a shrinkage of the market share of involuntary producers. Under these conditions, even though the per-tonne price might increase, the drop in sales volumes would mean a net reduction in revenues to the involuntary producers. If the prices were lower than their average cost of production, voluntary producers would reduce production and the market share of involuntary producers would expand. But they would be unable to supply all the global demand and would soon use up their reserves. After a disastrous period of low prices in the early 1970s, prices for sulphur stabilized and generally rose in response to increased world demand, although during the last few years they have declined somewhat. Thus, reserve stocks could be responsibly managed by liquidating them when the price rises above the long-term price trend and by building them up when the price falls.

Chapter Four

Legislation

Most environmental and conservation matters in Alberta are governed by provincial acts and regulations administered by provincial agencies. Projects within municipal boundaries or on federal lands can involve a variety of government levels and agencies. The Navigable Water Protection Act is administered by Transport Canada for all projects which involve the crossing of navigable waters. Other federal legislation that might come into play in developing Alberta's oil and gas resources includes: the Fisheries Act, administered in Alberta by Alberta Forestry, Lands and Wildlife, and the National Parks Act. Although the management of water resources is within the mandate of the provincial government, fisheries is the responsibility of the federal government. The Fisheries Act prohibits the deposit in waters of any substance harmful to fish or fish habitat or destruction of fish habitat. Under the National Parks Act, land set aside for national parks is off limits for oil and gas exploration and development.

Under the Migratory Birds Convention Act, charges can be laid for polluting an area frequented by migratory birds. The Act also protects nesting areas and the depletion of the various species. The Wildlife Act, administered by Environment Canada, is designed to protect, conserve and interpret aspects of wildlife in Canada. This Act works in conjunction with provincial legislation but can also be used to limit access to federal wildlife sanctuaries or bird sanctuaries. The Indian Act covers the exploration and production of oil and gas on Indian Reserves. Although these lands are administered by the federal government, the standards of Alberta Environment are usually the requirements that must be satisfied.

In 1938, the Alberta Government established "The Petroleum and Natural Gas Conservation Board" (PNGCB) — forerunner of the Energy Resources Conservation Board (ERCB). It was set up to deal with reservoir pressure and ultimate recovery problems associated with excessive flaring of gas in the Turner Valley Field and to control the general production of oil wells. The basic principles upon which the Board was founded were: to encourage development of the resources, to protect the public interest, and to ensure that resources were not wasted (ERCB 1987a). The concept, then as now, was that energy development should be orderly and efficient, with due regard to the needs of future generations.

As oil and gas drilling increased, the Board moved to assert and expand its influence. In 1947, the Leduc-Woodbend Oil Fields were declared an "Administrative Area" subject to the Board's good production practices to enhance ultimate recovery. This meant that well spacing and production limits imposed by the Board had to be followed. In 1949, the Board was given responsibility for issuing removal permits for gas judged to be surplus to Alberta's own requirements for the next 30 years. The Board thus became responsible for assessing Alberta's reserves of gas and determining its long-term requirements for natural gas. This 'surplus' requirement was subsequently decreased to 25 years. ERCB Decision 87-A reduced it to 15 years, including only core requirements —

those of residential, commercial and small industrial users.

In 1950, legislation gave the Board power to share out or prorate the available markets for Alberta oil among all producers. A formula was developed that provided for economic and orderly well spacing and direct rewards for improving oil recovery. It incorporated provisions that ensured equitable withdrawal of the resource. With modifications, this system is in use today. Unlike natural gas, the Board has never had a requirement for protection of oil supply.

In 1970, the ERCB, through amendment to The Oil and Gas Conservation Act, was directed to control pollution above, at, or below the surface in the drilling of wells and in operations for the production of oil, gas, and crude bitumen and other procedures over which the Board has jurisdiction. In 1971, the new Energy Resources Conservation Act broadened the ERCB's mandate "to control pollution and ensure environmental conservation in the exploration for, processing, development and transportation of energy resources and energy" (R.S.A. 1980: c.E-11). The Board's increasing responsibilities coincided with growing public awareness of environmental and social concerns. This increased awareness centered on the perceived potential for environmental impacts arising from energy developments, as well as the significantly increased effects of energy developments on individual landowners. In 1972, a separate division was formed within the ERCB to deal with environmental matters and to work with Alberta Environment, other government departments, the energy industry and the public.

Public hearings have become an important feature of the ERCB's approval process and are legally required for certain applications if there are legitimate objections to a proposed development. Initially, the major concerns voiced at hearings were related to the economic and technical feasibility of the proposal and its impact on conservation of the resource. The hearings provided an opportunity for industry proponents or opponents of particular projects to voice their positions and for industry representatives to make submissions regarding ERCB policies and practices. Environmental impacts were generally treated as possible side effects.

By the mid-1970s, ERCB hearings increasingly involved not only industry representatives but also public interest groups and individual Albertans. This trend continues today. But hearings involve substantial costs to the ERCB, the applicant and often to the intervener. In recent years, the ERCB has experimented with various approaches to resolve public concerns without the necessity of public hearings. This desire to improve public involvement is reflected in the ERCB Informational Letter: *Public Involvement in the Development of Energy Resources* (ERCB 1989). This Letter sets out the expectations for effective human and community relations held by the ERCB and Alberta Environment. These expectations include fostering a more thorough understanding of the needs and concerns of all those involved in energy developments and ensuring that people's concerns are addressed and resolved through public involvement programs.

In general, before any energy project can proceed, applications must be submitted to the ERCB. ERCB approvals and licences must be obtained. The ERCB acts as a "one-window approach" for most approvals. Exploration permits and Heritage Resources approvals, which are exceptions to this approach, are obtained through Alberta Forestry, Lands and Wildlife and Alberta Culture respectively. Water crossing permits and water withdrawal licences are obtained through Alberta Environment. Development and Reclamation Approvals are granted by Alberta Environment but application is still through the ERCB. In fact, many projects require joint approvals from the ERCB, Alberta Environment and Alberta Forestry, Lands and Wildlife. Approvals for plant sites are also required in compliance with the Planning Act,

although well sites, batteries, and pipelines are exempted.

An important part of the project review and approval process is the environmental impact assessment. The Land Surface Conservation and Reclamation Act authorizes the Minister of the Environment to order preparation and submission of reports assessing the environmental impacts of proposed developments. Alberta Environment requires Environmental Impact Assessments on most major resource developments proposed in the province including: major sour gas processing plants, oil sands mining projects and associated processing facilities, *in situ* oil sands projects, large-scale industrial facilities and major pipelines. Environmental Impact Assessment reports are to be prepared and submitted in accordance with the Environmental Impact Assessment Guidelines (Alberta Environment 1985). Alberta Environment and the ERCB have jointly issued several project-type information guidelines covering applications to the ERCB.

The Environmental Impact Assessment report must contain an identification of possible impacts, an analysis of their significance and an environmental protection plan to mitigate any adverse effects. The report must also identify those adverse environmental impacts that cannot be satisfactorily resolved and an analysis of their implications. Proponents are expected to maintain direct contact with appropriate agencies during the preparation of the report. They are also required to include in the Environmental Impact Assessment process the people who would be affected by a proposed development. Environmental Impact Assessments on energy projects requiring ERCB approval are to be filed with Alberta Environment and the ERCB as part of the application. The public has an opportunity to express its views on the environmental implications of the proposed energy development at the ERCB hearings. ERCB approvals and licenses frequently incorporate conditions to protect the environment and may also require that data be submitted to verify compliance with the specified conditions.

A wide variety of other approvals (for example, permits, licenses) may be required depending on the particular circumstances of the project. Table 2 provides a summary of the approvals that may be required for various activities.

To assist the petroleum industry in identifying which approvals are required from which agency, the Canadian Petroleum Association issued Environmental Operating Guidelines in 1980 (updated in 1988), which provide a description of the provincial regulatory processes, including provincial acts and regulations that have environmental implications.

The following are the main approvals that may be required:

1. Exploration approval — Forest Land Use Branch, Alberta Forestry, Lands and Wildlife
2. Approval for well drilling, production facilities, pipelines (technical and land use aspects) — ERCB
3. Development and Reclamation Approvals and Certificates — Alberta Environment, Alberta Forestry Lands and Wildlife
4. Surface Rights on Public Lands — Public Lands Disposition Branch, Alberta Forestry, Lands and Wildlife.

The following provides a brief overview of the responsibilities of the primary government agencies regulating environmental matters.

Energy Resources Conservation Board

The Oil and Gas Conservation Act and its Regulations can deal with many of the common environmental impacts. Specifically, the

Table 2. Approvals, Permits and Licences Potentially Required for Petroleum Developments

AE – Alberta Environment

ERCB – Energy Resources Conservation Board

AFLW – Alberta Forestry, Lands and Wildlife

Approval/Permit/Licence	Development Activity: Exploration	Drilling	Production	Pipelines	Power Lines	In Situ	Acess Roads	Stream Crossings	Gravel & Borrow Pits	Camps
ERCB Approvals/Licences										
• Permit to Construct/Licence to Operate			•	•		•				
• Well Licence		•				•				
• Abandonment of a Well or Formation		•	•							
• Application to Report Production			•							
• Notice of Commencement/Suspension of Production			•							
• Production Spacing Unit		•	•							
• Flaring Sour Gas		•	•	•						
• Gas Processing			•							
• Plugging Back a Well		•								
• Resume Drilling Operations		•								
• Suspend Drilling Operations		•								
Surface Rights (AFLW) (Public Lands Disposition Branch)										
• Initial Environmental Assessment (IEA)	•	•	•	•	•		•	•	•	
• Licence of Occupation (LOC)							•			
• Mineral Surface Lease (MSL)		•	•			•	•		•	
• Pipeline Installation Lease (PIL)				•						
• Pipeline Lease Agreement (PLA)				•						
• Miscellaneous Lease (gas plant)			•							
• Miscellaneous Permit		•	•	•						•
• Surface Materials Licence/Lease (SMC)		•	•	•				•	•	
• Easements					•					
Surface Rights Board - Right of Entry		•	•			•				
Exploration Approval/Licence (AFLW) resulting from expl. & review	•								•	
Tree Freeing Authority (AFLW)					•					
Burning Permit (AFLW)	•	•	•	•	•		•		•	•
Reclamation Certificate (AE &/or AFLW) comple. of reclamation	•	•	•	•		•	•		•	•
Development & Reclamation Approval (AE) for Regulated Pipeline				•		•			•	
Clean Air Permit/Licence (AE) (Standards & Approvals Div.)			•	•		•				•
Clean Water Permit/Licence (AE) (Standards & Approvals Div.)		•	•	•		•		•	•	•
Water Resources (AE) (Water Resources Branch)										
• Licence to Divert Water		•	•	•					•	•
• Drainage Licence	•	•	•		•	•	•	•		
• Permit to Construct Works Near or Across a Stream		•	•	•			•	•	•	
• Permit for Exploration (Ground water wells)						•			•	
• Groundwater Well Registration (for domestic use)		•	•	•						•
Pesticides Permit (AE), Herbicides Permit (AE)		•	•	•	•	•	•	•	•	•
Historical Resource Permit (Alberta Culture)		•	•	•	•	•	•		•	•
Navigation Permit (Transport Canada)				•			•	•		
Crossings (Pipelines, Road, Transmission lines)	•			•	•		•			
Road Use Agreements, Land Withdrawals	•	•	•	•		•	•			
Letters of Notification to Counties, M.D.s & I.D.s	•	•	•	•		•				
Letter of Notification - Trappers	•	•	•	•	•	•	•		•	•

ERCB approves applications for wells, production facilities, pipelines and gas plants; inspects and monitors field operations of the petroleum industry; and monitors spills, sour gas emissions, noise and emergency response plans.

Several statutes administered by the ERCB require approval by the Minister of the Environment.

Alberta Forestry, Lands and Wildlife

Under the Public Lands Act, Alberta Forestry, Lands and Wildlife is responsible for the authorization and regulation of all operations on Crown land under its administration and control. This includes the vast majority of provincial Crown lands but excludes the Special Areas and Metis colonies and provincial parks. Authority must be obtained to enter, occupy, or utilize any Crown lands. The Department also monitors all industrial activity in the Green Area. All applications for exploration and development programs in the Green Area must be reviewed by the Department. These reviews cover impacts on fish and wildlife habitat, timber, recreation and grazing reserves. Alberta Forestry, Lands and Wildlife also provides integrated resource policy and planning services, administration and management of public lands; and co-ordination of all government surveying and mapping activities. It is responsible for reclamation orders and certificates on public lands for development projects not requiring Development and Reclamation approval from Alberta Environment. Alberta Forestry, Lands and Wildlife also monitors public lands for vegetation damage, inspects for erosion, and looks after fire prevention and appropriate sump location and handling. Fish and Wildlife staff monitor rivers, streams and lakes for pollution which may affect fish or wildlife.

Some authority for Reclamation and Development Permits has been delegated to Alberta Forestry, Lands and Wildlife by Alberta Environment. Forestry, Lands and Wildlife also may issue letters of authority and/or dispositions under the Public Lands Act for activities that may cross some bodies of water.

Alberta Environment

On the basis of the detailed environmental features of a project, Alberta Environment establishes the terms and conditions of permits and licences that are required by legislation. The approvals include those that may be required under the Forest Act, the Water Resources Act, surface rights approval from private land owners or the government under the Public Lands Act, planning approval under the Planning Act, and environmental approvals under the Clean Air Act, the Clean Water Act, and the Land Surface Conservation and Reclamation Act.

Alberta Environment is responsible for Development and Reclamation Approvals for all lands in the province, and for issuing reclamation orders and certificates for all developments on private lands. For regulated projects on public lands, the reclamation orders and certificates are issued jointly with Alberta Forestry, Lands and Wildlife. Alberta Environment is responsible for approvals of stream diversions, drainage and water uses, controls of liquid effluents and air emissions, issuance of ministerial consents in Restricted Development Areas (RDAs), issuance of Water Resources Permits for stream crossings (pipeline and road), issuance of Pesticide Application Permits and issuance of ministerial approvals for pipelines referred to Alberta Environment by the Energy Resources Conservation Board.

Alberta Energy

Alberta Energy is responsible for the administration and management of Alberta's mineral resources. It decides which mineral resources should be available for develop-

ment, provides policy recommendations on energy to the government, establishes and administers the fiscal regimes and royalty system, and administers energy-related research, development and conservation programs.

Although the one-window approach works relatively well, conflicts still arise through differences in interpretation of legislation and regulations by government officials and industry, the use of ministerial discretion and political decision making. Industry usually prefers the option of using guidelines as a means of describing and guiding expectations of compliance but often finds that the government interprets guidelines as being specific requirements instead of expectations. This difference in interpretation can create conflicts.

Industry is concerned with the increasing amount of legislation and regulation dealing with environmental offences. Of particular concern is the tendency for government to penalize industry as a whole through greater regulations and fines when an offence is committed rather than penalize the offending company.

Industry requires consistent, clear policies to ensure environmental protection and compliance. Industry as well as the public should be involved in the development of these policies which must take into account both environmental safety and economic considerations.

Chapter Five

Interactions With Other Sectors

Energy development, like many other types of industrial development, has both positive and negative effects on the economy, on our ability to deliver social programs and on the environment. In recent years, the oil and gas industry has taken major steps to reduce the negative impacts of its operations. Some actions have been taken to conform with federal, provincial, and local regulations and guidelines but others were taken because companies "recognize that they must incorporate environmental planning into their decision-making process and use the best practical technology to minimize the impacts of their operations on the environment and on public health and safety." (CPA 1987b: 2). The Canadian Petroleum Association, for example, has developed, in consultation with the public and government agencies, a code of practice which translates its commitment to minimize environmental impacts into action (CPA 1987b).

As a result of these types of initiatives, as well as tighter regulations, many earlier concerns about the industry have diminished. However, because of its ubiquitous nature, oil and gas development continues to present significant environmental impacts. The severity of some impacts is expected to increase. For example, the Energy Caucus of the Alberta Environmental Network (AEN 1989) has identified the following as major issues: energy development in the eastern slopes, oil sands and heavy oil developments, and air quality concerns related to sour gas developments. The Energy Caucus paper also states that the most pressing questions regarding Alberta's energy future are what ways and means can be found to alleviate the environmental stress that the present projections of growth in energy demand would bring to the province (AEN 1989).

Conflict may arise even before petroleum exploration takes place in the decision about which areas are to be opened for exploration and possible development. To date this has been primarily a bureaucratic decision influenced by industry interest and information about potential oil and gas resources in an area. There is no process for public discussion about the desirability of resource development in an area. As a result, conflict has arisen, especially in areas with other highly-valued resource uses. The integrated resource planning process of Alberta Forestry, Lands and Wildlife attempts to resolve conflicts and establish a policy position prior to development. While this policy decision is often based on input from public reviews, there often remains resistance by special interest groups who oppose the policy decision.

As proven reserves are developed, pressure is likely to increase to develop potential reserves within the prime protection zone of the eastern slopes (AEN 1989) as well as in other protected areas such as ecological reserves and provincial parks. For example, controversy has already developed over exploration and development activities taking place in the South Castle area in the southwest corner of the province.

In areas of the province that are not as ecologically sensitive as the prime protection zone, oil and gas exploration is more

straightforward, although not without effects on other resources and resource uses. A major challenge of the next decade could be the resolution of the demand for lands which would provide a traditional lifestyle for Alberta's native and Metis populations. Petroleum and forestry developments have continued despite the number of outstanding native land claims. Resolution of these claims in an amicable and fair manner will provide a challenge of the highest order.

For convenience, the discussion of interactions focuses on the four phases of oil and gas industry activities: exploration, development, production, and abandonment.

Exploration

Exploration for hydrocarbon resources begins with attempts by seismic and geophysical crews to locate the most promising areas for drilling. Before drilling on Crown land, it is necessary to obtain a licence through government-run land sales auctions. Exploration involves negotiation of access to land areas, and seismic activity to determine likely areas of reserves. Once seismic activity has indicated promising areas, exploratory drilling takes place in hopes of hitting oil and gas reservoirs.

Seismic operations and associated activity in the area may disturb wildlife in critical habitat areas. Disturbance, especially during the winter, can lead to increased mortality. The seismic lines cut in forested areas also provide easier access for hunters, fishermen and a wide spectrum of outdoor enthusiasts including trekkers, ATV users, cross-country skiers and snowmobilers. Most of these respect the interests of other forest users and behave with consideration for the environment. Nevertheless, improved access increases user pressure.

On some areas of Crown land, the Department of Forestry, Lands and Wildlife has attempted to make seismic cutlines impassible to ordinary vehicles although it is almost impossible to prevent access by all-terrain vehicles. The procedure of rolling vegetation back onto seismic lines helps to control erosion and limit vehicular access. The sites chosen, length of rollback, purpose (erosion control or access restriction), and extent of debris left on the site are site-specific decisions made by Alberta Forestry, Lands and Wildlife after very extensive interdepartmental and interagency review.

Seismic lines in forested areas may be used by wildlife as travel corridors. Forest habitats may be lost through clearing but the cleared areas often grow back with grasses and shrubs that provide desirable forage for such species as deer, moose and elk.

In forested areas, timber cut for seismic lines may be used by local sawmills or pulp mills. Clearing of the right of way may result in a loss of merchantable timber if the felled and piled trees are too far from a mill for economical transportation. There also may be an indirect loss of timber through blow downs or disruption of forest harvesting patterns if the regenerated forests are out of sequence with cutting plans for the surrounding timber. Periodic reuse of the same cutline may prevent regrowth of forests suitable for harvesting.

In settled areas, seismic operations are often conducted along road allowances with little disruption of adjacent land. Complaints arise that seismic holes adversely affect groundwater wells through the creation of flowing holes or because the seismic explosion disturbs underground formations and disrupts groundwater flows.

When exploratory drilling is planned, land must be leased or purchased for the well site. The provincial economy benefits from the "sale" of exploration rights on Crown land except where this development occurs on agricultural dispositions on Crown land. Although the Crown still owns the mineral resources under these circumstances, the lessee receives payment rather than the Crown. On private land, the landowners benefit from payments for access agreements which must be negotiated with them although

they sacrifice some privacy and land use opportunities. The Crown as owner of the resource (except where mineral rights are attached to land titles obtained before the turn of the century) retains the revenues from the sale of mineral rights.

In forested areas, clearing is required before drilling can take place with impacts similar to those mentioned for seismic lines. In agricultural areas, agricultural capability will be lost temporarily when the land is removed from production. Drilling of wells may cause difficulties related to management of drilling fluids and brines as well as other problems such as visual impacts, noise of drilling, vehicle traffic and soil erosion or compaction around the site.

Seismic data and the analysis of drill cores from exploration wells could provide valuable information about Alberta geological history and resources, and geothermal potential (Alberta Energy 1986). Other information such as data on mineral resources could be gathered if cores from shallow depths were logged.

The safety of drilling operations is regulated by the Energy Resources Conservation Board. Although the potential exists for well blowouts and possible air and water pollution, few such events actually occur. Concerns may also arise over the safety of persons near drilling sites. The consequences of a blowout could be severe and the ERCB enforces strict directives covering drilling procedures and safety requirements. Since the Lodgepole well blowout in 1983, public concern over sour gas well drilling in particular has been high. The ERCB has strengthened rules aimed at preventing blowouts during drilling of sour gas wells. The ERCB has created a new category of sour well known as a critical well. This designates sour wells where blowout prevention is of paramount importance because of the potential for serious consequences if a blowout should occur.

Development

If seismic work and exploratory drilling indicate that there are adequate reserves, then the extraction phase begins. Stepout wells are required to delineate the size (depth and area) of the reservoir and to optimize extraction rates and volumes. The increase in the number of well sites means that more land is required for drilling pads, battery sites and access roads. Earlier concerns over the removal of lands from other uses have been reduced by changes in well location requirements which now allow drilling in the corners of quarter sections instead of the center. This reduces the length of access right-of-way required from the nearest road allowance. It also allows crews to position well sites in adjoining quarters, further reducing the need for access roads.

Access roads and sometimes power and water lines are needed to service wells. The construction of roads may allow access by a range of other vehicles. This can be controlled by gates on roads that lead directly to well sites. Other roads leading to an oil or gas field remain accessible and may be shared with other users such as the forest industry. Restricting access to larger areas of forested land can be done through Forest Land Use Zones or other zoning policies such as the Eastern Slopes Policy. Careful planning of road access needs for all users can substantially reduce conflict among competing interests.

With greater drilling activity, the likelihood of accidental releases of oil or gas, drilling fluids, or brine increases. Yet inspections by the ERCB encourage companies to comply with government regulations and the incidence of accidental releases remains low. Inspections by Alberta Forestry, Lands and Wildlife staff encourage compliance with land use permits, environmental standards and so on.

Development of heavy oil deposits requires closer spacing of injection wells and pumps than with conventional oil. The land

use impact of these developments has been minimized by directional drilling from a grouping of wells on a shared site instead of drilling from many separate pads. *In situ* heavy oil developments require large volumes of water for steam injection systems. This demand may conflict with other local water uses. Strict control of water withdrawals and volumes are required.

The first "horizontal" well was recently completed in a heavy oil reservoir. This technology, although currently very expensive, allows the recovery of considerably more oil through a single horizontal well than through traditional wells. Widespread use of this technology in the recovery of heavy oil could drastically reduce the amount of land required for heavy oil developments while substantially increasing recovery of the heavy oil.

Large amounts of sand and gravel are used in constructing drilling pads, well sites, batteries, and access roads. Heavy oil and oil sands projects have especially large gravel requirements because of the complex infrastructure required and the muskeg terrain in which most oil sands are located in Alberta. In some areas, the demand for sand and gravel by the energy industry may place a stress on its availability for other uses. This has raised concern about the long-term availability of sand and gravel. Drilling operations may also have significant impacts on other local land uses such as agriculture, forestry, hunting, fishing, trapping and the tourism potential of the area.

Development of "mineable" oil sands reserves brings its own special problems. Multi-billion-dollar plants require hundreds of workers during construction and large numbers to operate the completed plant. The socioeconomic and environmental impacts of these developments on local communities are substantial. Large areas of land are mined for the tar sands and must be reclaimed. Processing produces large volumes of tailings which are emitted to lake-size tailings ponds. Accidental releases or spills of waste have, in the past, contaminated water bodies and resulted in closure of fisheries in the Athabasca River. Air emissions include sulphur dioxide, hydrogen sulphide and heavy metals that could affect regional air and water quality, vegetation and soils.

Production

Full development of oil and gas reserves requires much more than the land base for production wells. Processing plants are needed, plus pipelines to move product and byproducts from wells to processing plants and carry the finished products to market. These developments, in total, have large land requirements, often in agricultural areas. Greater effort has been made in recent years to respond to concerns about the loss of agricultural land to industrial development and the establishment of facilities on Crown land. Regional and local plans provide assistance in planning. Industrial development is encouraged to locate on lower-quality agricultural land. Alberta's integrated resource planning process has been used to determine areas for industrial development in some areas of Crown land.

Heavy oil recovery operations produce large amounts of oily sand as waste. The common disposal method has been to use this material on local roads. As technology has developed to clean these wastes and produce clean sand and saleable oil, this method of disposal is being discontinued.

Pipeline construction procedures also have improved markedly in the last decade or so. Where possible, timber from pipeline rights of way is salvaged. These rights of way may be used by both wildlife and people for easier movement in forested areas. In agricultural areas, special care is taken to ensure that disturbed areas are reclaimed to agricultural use through careful topsoil salvage and replacement. Guidelines for pipeline construction are intended to minimize the impact on agricultural productivity, on water courses that are crossed by pipelines, on timber harvesting operations and so forth.

Rural residents and municipalities often face conflicting points of view over the desirability of industrial development. Concerns relate to impacts on the social fabric of the community, on the environment, and on health and safety aspects of industrial facilities as well as the effect of increased population on local services and infrastructure. Benefits accrue to the area from local job creation, improved cash flow into a community, improved local infrastructure, and increased tax revenues, but these benefits do not flow evenly to all sectors of the local economy. With any major development, some people will feel that they have suffered. These concerns, while not unique to the oil and gas industry, arise more frequently simply because of the ubiquitous nature of the industry in Alberta. Local advisory committees, the Energy Resources Conservation Board hearings on project proposals, and the Surface Rights Board are some of the mechanisms that Alberta has in place to address these concerns. As well, the ERCB specifically encourages companies to meet with concerned citizens and resolve problems instead of relying on the hearing process (ERCB 1989).

Environmental concerns related to oil and gas development range from specific local impacts to the global climatic implications of burning fossil fuels. Impacts on the local environment arise from the alteration of habitat and land use, disturbance of wildlife populations and water pollution resulting from spills or accidental releases, plant effluents and pipeline breaks. Other impacts could occur from permitted emissions, plant upsets, wet or dry deposition of acid-forming emissions and the creation of lake-size tailings ponds as a byproduct of oil sands processing.

The tailings ponds associated with oil sands extraction processes pose a long-term environmental hazard. The oil sands plants, which use a hot water extraction process, produce considerable quantities of water containing clay and silt, bitumen, caustic soda, heavy metals, phenols and naptha. At present, this effluent is pumped to tailings storage facilities for permanent impoundment. After settling, clarified water is recycled to the oil sands extraction plant. The remaining liquid consists primarily of millions of tonnes of sludge which has poor settling quality and a high water content, giving it the characteristics of fluid. The tailings ponds are the largest in the world. At the end of an oil sands plant's life, the ponds may cover 20 to 30 square kilometres behind dykes 50 to 100 metres high. No practical and environmentally safe method has been found to dry the sludge and reclaim the area although this is a subject of considerable research.

Longer-range environmental problems associated with oil and gas production relate primarily to air emissions. These include acid-forming emissions produced at sour gas processing plants, and increases in concentrations of carbon dioxide and oxides of nitrogen in the atmosphere resulting from the processing and use of fossil fuels.

For example, concerns over present and future regional impacts of acidic or acidifying pollutants discharged within Alberta resulted in a major provincial government and industry research program. These concerns include those related to impacts on air and water quality, vegetation and soils, as well as human and animal health. To date these studies have indicated "it is extremely unlikely that, except in the immediate vicinity of point sources, there is any impact on any of these environmental components" (crops, soils, and surface waters) (Legge 1988: 73). However, one area was discovered in which alfalfa yields were well below those predicted by computer models. It is possible that sulphur dioxide was one factor in the depression of these yields. Elevated levels of ozone were found in some locations. The report states that the possibility of sulphur dioxide affecting crop yields would be increased if the area also experienced elevated ozone concentrations.

Alberta includes a number of soil types that are very slightly buffered and susceptible

to acidification. For example, major increases in deposition of acidic pollutants could significantly accelerate acidification of forest soils including those in northeastern Alberta, where future development of oil sands and heavy oil will be concentrated. Work is now being done to develop interim target loadings for these more sensitive areas.

Elevated ozone levels are of concern to human health and ozone sensitive crops. Ozone is produced in the lower atmosphere from photochemical reactions involving nitrogen oxides (NOx) and volatile organic compounds (VOC). Canada has signed a United Nations protocol which calls for a freeze on emissions of NOx at their 1987 levels by 1994 followed by further reductions. A working group has also been established to develop recommendations for a VOC emission control protocol.

Control strategies may involve the application of best available technologies to emission sources, tightening new vehicle emission standards, and implementing standards for new diesel engines. Improvements in energy productivity and conservation should be a key feature in the plan of action (Federal/Provincial LRTAP Steering Committee 1989). The implementation of any plan of action will have far-reaching effects on Alberta's energy industry. It will affect both the demand for energy resources and the operation of the processing and refining industry which is a major source of the emissions.

Another issue with perhaps even more significant impacts for the production of Alberta's oil and gas resources is the global increase in atmospheric carbon dioxide levels and its possible implications for climate change. In opening comments to the Conference on The Changing Atmosphere, Madame Brundtland, Prime Minister of Norway, said that consequences of global climate change could be more drastic than any other challenge except nuclear war (WMO 1988). The Conference delegates called for a reduction in carbon dioxide emissions of approximately 20 percent of 1988 levels by the year 2005. Alberta Energy is participating in the Federal-Provincial Task Force on Energy and the Environment which is determining options available to reduce energy-related CO_2 levels in Canada and examining the implication of achieving the Conference recommendations.

Alberta produced approximately 112 megatonnes of CO_2 in 1988, about 20 percent of the energy-related CO_2 emissions in Canada. Emissions are projected to increase to 157 megatonnes by 2002 (Burn 1989).

Roughly one-half of the energy-related carbon dioxide emissions in Alberta are from natural gas and propane. This includes: combustion of natural gas, which accounts for 86 percent of gas-related carbon dioxide; use of gas as a feedstock in the production of other compounds such as hydrogen; and release of raw CO_2 produced with the raw gas. In the future, the requirements of new oil sands plants are projected to account for substantial amounts of gas, primarily as a fuel but also as feedstock.

Another one-quarter of the carbon dioxide emissions are from coal, used almost exclusively to generate electricity. The remaining one-quarter comes from refined petroleum products, including the coke and process gas used as fuels in the oil sands plants, as well as petroleum products used in transportation, residential, commercial and farm uses, and by the energy industry.

Approximately one-third of Alberta's current carbon dioxide emissions are produced by the energy industry. This totals 38 megatonnes per year, including 12 megatonnes from the gas processing industry. The refined petroleum products, coal and gas are produced not only to meet Alberta's needs but also for other parts of Canada and the United States.

As Burn (1989) points out, the challenge of reducing carbon dioxide emission levels in Alberta by 20 percent by 2005 could have a major impact on the province. A 20 percent reduction below 1988 levels actually trans-

lates into a drop of about 40 percent below the emission levels currently forecast for 2005.

Policies and programs developed to deal with these international and global energy-related environmental issues could have major consequences for world energy markets and prices, as well as on the development of Alberta's energy resources, and the economics of Alberta's energy industry. Environmental and social concerns could become the main factors affecting Alberta's energy future.

The recovery of sulphur from sour gas, originally required in the early 1950s when there were no markets for the recovered sulphur, has now developed into an industry in its own right. Increased requirements for sulphur recovery have greatly reduced sulphur emissions from sour gas plants over the past decade. Emissions are projected to decrease further as the 1988 guidelines (ERCB 1988b) are applied to new sour gas plants and older plants with lower sulphur recovery capabilities are removed from production. The technology for processing, storing, and reprocessing sulphur also has changed. This has reduced the localized impacts previously caused by the blowing and deposition of dry sulphur. Yet increased sulphur emissions could result from expanded development of the oil sands. Even though sulphur recovery rates at existing oil sands plants are being improved, additional plants would add to area loadings. Northeastern Alberta and the bordering corners of Saskatchewan and the Northwest Territories are more sensitive to acid deposition than most areas of Alberta and may be seriously affected if production of oil (and sulphur) from the oil sands increases substantially.

Technology and environmental standards have changed significantly since the first oil sands plants were approved. For example, Syncrude applied to the ERCB in 1984 for approval to increase production by 20 percent. But by including a hydrocracker and tail gas clean up equipment in the expansion, emissions of sulphur dioxide and heavy metals could be reduced. The company is considering a further substantial expansion — with no increase in emissions.

Surface mining of the oil sands and the subsequent separation and upgrading processes will inevitably have significant environmental impacts. Although the reserves are located in a remote area of the province where the land is not suitable for agriculture, native communities are situated in the general area. Fort McKay, on the Athabasca River, is located only about 10 kilometres north of the existing plants and would likely be in the center of further mining developments.

Abandonment and Reclamation

After pools of hydrocarbons have been depleted, well sites, pipelines, roads and processing plants may have to be abandoned. Abandonment of smaller facilities such as well sites, roads and pipelines pose little difficulty and reclamation to a suitable land use may be accomplished with few difficulties. Abandonment of plant sites is much more difficult. The provincial government currently addresses industrial site reclamation on a case-by-case basis as few such facilities have so far been closed and abandoned.

Reclamation costs are borne by the company. For sites where the company responsible is no longer in existence or is unknown, reclamation work may be done with funding from Alberta Environment.

Alberta Environment, Land Reclamation Division, works very closely with the ERCB on the land surface reclamation of abandoned well sites, pipelines, access roads and so on to ensure that the land is returned to the same productive capability that existed prior to disturbance. Under the authority of the Land Surface Conservation and Reclamation Act, Alberta Environment has issued guidelines for the reclamation of land affected by surface disturbance (Alberta Environment 1977). These guidelines are to be used in the

assessment and development of reclamation plans as well as in the inspection of sites, including oil and gas pipelines, which require a reclamation certificate. These guidelines cover drainage and erosion control, conservation of materials for reclamation, recontouring of disturbed lands, restructuring of the root zone and revegetation. The end use of the land must comply with any area's Integrated Resource Plan, the Planning Act and the broad "zoning" of Regional Plans. Nevertheless, areas of concern exist over the end use of reclaimed areas, especially on Crown lands.

Research, funded from the Heritage Savings Trust Fund, is under way to identify the most efficient methods for achieving acceptable reclamation. Topics include reclamation of dykes around oil sands tailings ponds, storage and overburden dumps and disposal of drilling wastes.

"Orphan" wells may become a major concern, where wells are leaking or not properly abandoned. These are wells with no known ownership. Responsibility for the well is then passed to the Crown and the ERCB assumes responsibility for any necessary work.

Most orphan wells were drilled during the 1940s and 1950s but, with about 24,000 inactive or suspended wells in the province, the number of true orphan wells could rise. The ERCB presently has about 50 true orphan wells on the books that it will have to deal with at some point. The ownership of about 200 other wells is in limbo because of companies going into receivership.

The ERCB administers a $3 million fund set up to deal with orphan wells. Interest income from the fund has been used to carry out the work. During 1988, the ERCB spent more than $500,000 dealing with three orphan wells (ERCB 1988a).

The 24,000 inactive wells also need to be dealt with. Many of these marginal wells should be abandoned and the land surface reclaimed for agriculture, forestry or wildlife habitat.

Resolving Conflict

It is inevitable that conflicts will occur between the oil and gas development industry, other sectors and resource users. Community advisory committees may be established to discuss and resolve environmental and social concerns and to make the most of the economic benefits brought to a community by oil companies. Advisory committees, such as the Cold Lake Citizens Advisory Committee and the Fort McKay Interface Committee, have proven to be very successful mechanisms for dealing with local concerns and ensuring that development takes place with minimal environmental and social disruption. The Government of Alberta has also established an Advisory Committee on Heavy Oil and Oil Sands Development which provides a continuing liaison between the government and communities that may be affected by heavy oil or oil sands development. This Committee is chaired by an MLA and has membership from government departments and agencies, industry, and the general public. It advises the government on the need for, and scheduling of programs that provide public services and facilities in areas affected by heavy oil or oil sands development. The Committee hears and reviews concerns of residents over the possible effects of development and brings these concerns to the attention of government.

The Energy Resources Conservation Board, as the primary regulator of oil and gas development, is especially aware of the potential for conflicts. The Energy Resources Conservation Act makes specific provision for public involvement and is required to convene a public hearing if there are legitimate objections to a proposed development. Each hearing involves substantial costs to the ERCB, the applicant and often to the intervener. The ERCB has also concluded that its hearing process can be too formal, too adversarial, and often ineffective in resolving basic conflict between parties. As a result, the Board has experimented with various approaches to

resolve public concerns about energy project development.

The ERCB's support for conflict resolution is illustrated in a paper which examines the principles underlying the successful resolution of controversy surrounding Hewitt Oil (Alberta) Limited's application to the ERCB for a licence to construct a small sour gas processing plant southwest of Edmonton (Lilley 1988). The paper then considers alternative conflict resolution in the context of developing and implementing an Alberta Conservation Strategy. This analysis reveals a lack of adequate mechanisms in Alberta's present system for using conflict resolution. The report calls for mechanisms which recognize the legitimacy of negotiation and which encourage its use. Furthermore, Alberta needs clear policy direction to provide a framework for negotiations.

The interactions of the various users should be managed in the interest of achieving sustainable development. Thus the development of oil and gas resources should allow other uses to also be sustainable over the long-term, all of them making a contribution to Alberta's economy.

The Caroline Sour Gas Development

It was in the spirit of developing a plan that addressed the interests of all involved that local residents and the industry approached the exploitation of the Caroline Sour Gas Field in west central Alberta.

The Field was the largest sour gas discovery in Alberta in over two decades and possibly the largest sour gas discovery in the world. Plans were made to drill 20 wells into the high pressure, high volume reservoir which extends from Sundre in the south to just north of Caroline.

While approximately 16 companies own the reserves, Husky, Gulf and Shell have taken the lead in developing the Field. Piecemeal development of the resources was not viewed as desirable and the companies were encouraged by the ERCB to co-operate in their development plans. They subsequently formed the Caroline Sour Gas Development Group.

It was hoped that a co-ordinated plan would be developed that would be best for the industry, the environment and society, particularly the local residents. Development of a plan that adequately addressed this range of interests would require early and full public involvement and a complete economic, social, and environmental impact assessment including impacts on both animal and human health.

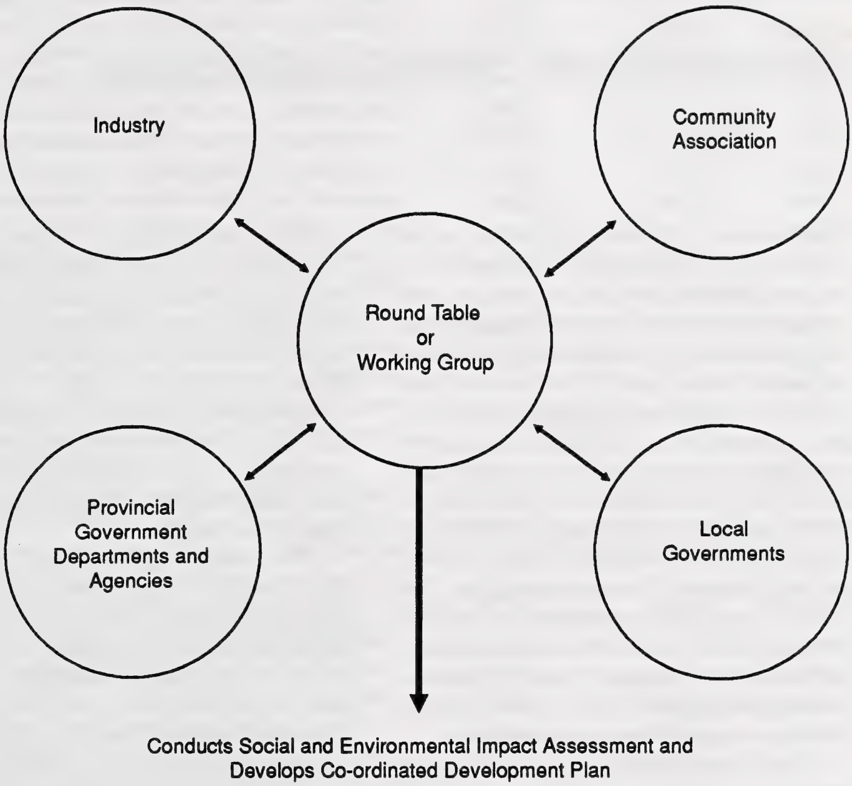
The development options initially announced by the companies were very general and included expansion of the existing Ram River (Husky) and Strachan (Gulf) sour gas plants southwest of Rocky Mountain House or construction of a new plant.

In keeping with the recommendations of the Report of the National Task Force on Environment and Economy (1987), it was recommended by local citizens that a working group or round table be formed with equal representation from industry, provincial government departments and agencies, local governments, and a community association. The group would be responsible for actually conducting the Environmental Impact Assessment and coming up with a co-ordinated plan for developing the sour gas field. The proposed working relationship is diagrammed in Figure 7.

Because the community would be playing a very proactive role, it was proposed that special funding be provided to the community association. It would use the funds to hire someone to assist in forming the association and encouraging anyone with concerns to join. This person would also help ensure good communications between the association's representatives on the working group and members of the association.

Funding also would be required for the community association to hire someone else to assist it in reviewing technical reports and

Figure 7. Proposed Involvement in Planning Development of the Caroline South Gas Field



to make sure that their concerns were being addressed. This process, which would be supplemented with public meetings and workshops, would increase the quality of the social and environmental assessment, ensure public involvement in planning and hopefully result in a better development for everyone.

The recommendation for a round table was rejected by industry. Instead, the municipalities appointed a Community Advisory Board which lacks broad public acceptance.

The Caroline Sour Gas Development Group subsequently decided to proceed with what was called the "selected option" which entailed both expansion of the existing plants and construction of a new plant.

Husky withdrew its support for the selected option because the Company viewed it as the worst option environmentally and the entire proposal fell apart. There are now two applications before the ERCB. Shell is proposing to process all of the gas at a new plant. Husky is proposing to process all of the gas at an expanded Ram River Plant. For the first time, the ERCB may have to make a decision between two major competing applications based on environmental, social, and public safety concerns.

Chapter Six

Economic and Social Significance

The discovery of crude oil at Leduc on February 13, 1947 brought the Canadian oil and gas industry into the modern era and began the greatest oil and natural gas boom ever experienced in Alberta or anywhere else in Canada. More than 3,700 wells were drilled in Alberta over the next five years. Oil production increased from 1.4 million cubic metres (9 million barrels) in 1947 to 10 million cubic metres (63 million barrels) in 1951 and by 1988 exceeded 79 million cubic metres (500 million barrels). The growth of the industry caused profound changes throughout the province as people, companies and money flowed in to develop the oil and gas resources and to service the petroleum industry. Alberta was transformed from one of Canada's poor provinces to one of the more prosperous.

Resource development creates direct jobs, and stimulates related industrial development in the service industry and by manufacturers of petroleum-based products. Resource development attracts secondary industries. During the 1970s, the provincial economy experienced unprecedented growth as oil and gas development activity increased dramatically. This growth was not without adverse effects. Rapid growth in population and in the demand for services stretched the capabilities of some municipalities. Average incomes grew rapidly, but so did the cost of living. Land and housing costs in urban and rural areas increased.

Then oil prices dropped and the boom ended. Unemployment rose as a recession hurt not only oil and gas exploration and development companies, but also a wide range of firms that depended on a booming petroleum industry as a market for their products and services. Wages and salaries dropped or remained stagnant, and many companies, especially oil field service companies, found their equipment on the auction block. Municipalities, farmers, entrepreneurs, investors, and individuals often found themselves burdened with debt accumulated in anticipation of continued good times. Housing prices plummeted and construction ceased.

For those who have lived in Alberta during the past decade, these economic impacts have been unmistakable. Alberta, despite the efforts of government over the past decade, still depends heavily for its economic well-being on the development and sale of its oil and gas resources and the chemicals and materials that are derived from these resources. In particular, provincial revenue is derived from "land sales" of exploration and development rights for the hydrocarbon resources, and royalties from their production. Changes in the economics of oil and gas exploration and development have an immediate effect on provincial revenues and the provincial economy in general.

Among the challenges facing Alberta is that expressed by the sixth objective of the *Prospectus for an Alberta Conservation Strategy* (PAC 1987): how to use and manage our non-renewable resources in the interests of developing a long-term sustainable economy for Alberta.

The growth of the petroleum industry was a major factor in the transformation of Alberta from a rural-based society into a highly urbanized and industrialized one. In 1941,

almost half of the labor force in Alberta, as well as in Manitoba and Saskatchewan, was engaged in agricultural activities. The rapid increase in Alberta's population coupled with the trend toward urbanization that was common across the prairies meant that by 1971, the agricultural labor force in Alberta had dropped dramatically to about 13 percent of the population compared with 19 percent in Manitoba and Saskatchewan. Over the same period Alberta's population doubled, from 796,000 in 1941 to 1.63 million in 1971. Manitoba's population increased from 730,000 to 990,000 and Saskatchewan's from 900,000 to 930,000 (Statistics Canada 1971). In 1986, the population of Alberta totalled 2.37 million representing over nine percent of Canada's population compared with seven percent in 1941.

In 1987, employment in the oil and gas industry plus the direct service industries accounted for seven percent of the Alberta labor force. Many others are employed in industries and services that expanded to serve the needs of the increased population: construction workers for roads, houses and office buildings, and staff for retail outlets, hotels, schools, government and so on.

Alberta's share of Canada's gross domestic product grew between 1961 and 1982 (Table 3), mainly as a result of oil and gas activity. In 1961, when Alberta was still considered to be a "have not" province, its share of Canada's gross domestic product (GDP) was 7.9 percent while its share of the population was 7.3 percent. In 1982, Alberta's share of Canada's GDP was 14.1 percent while the population had increased to 9.4 percent. Since 1982, as exploration and development activity has slowed, Alberta's contribution to the national GDP declined to about 10.7 percent by 1987.

The contribution of the oil and gas industry to Alberta's GDP is summarized in Table 4. In 1965, the contribution was 16 percent while in 1984 it had increased to 34 percent.

Table 3. Alberta's Share of Canada's Gross Domestic Product and Population

Year	GDP (Percent)	Population
1961	7.9	7.3
1971	8.0	7.5
1981	14.0	9.2
1982	14.1	9.4
1983	13.7	9.4
1984	13.5	9.4
1985	13.2	9.3
1986	11.5	9.4
1987	10.7	9.3

Source: Statistics Canada

Table 4. Industry Distribution of Alberta Gross Domestic Product

Year	Mining* (Percent)	Agriculture
1965	16.0	10.6
1970	17.6	6.7
1975	28.1	6.9
1980	34.2	4.7
1981	29.0	4.1
1982	29.7	3.6
1983	32.3	2.9
1984	34.0	2.7
1985	33.6	2.6
1986	21.6	4.4

* Primarily oil and gas sector plus natural resource royalties

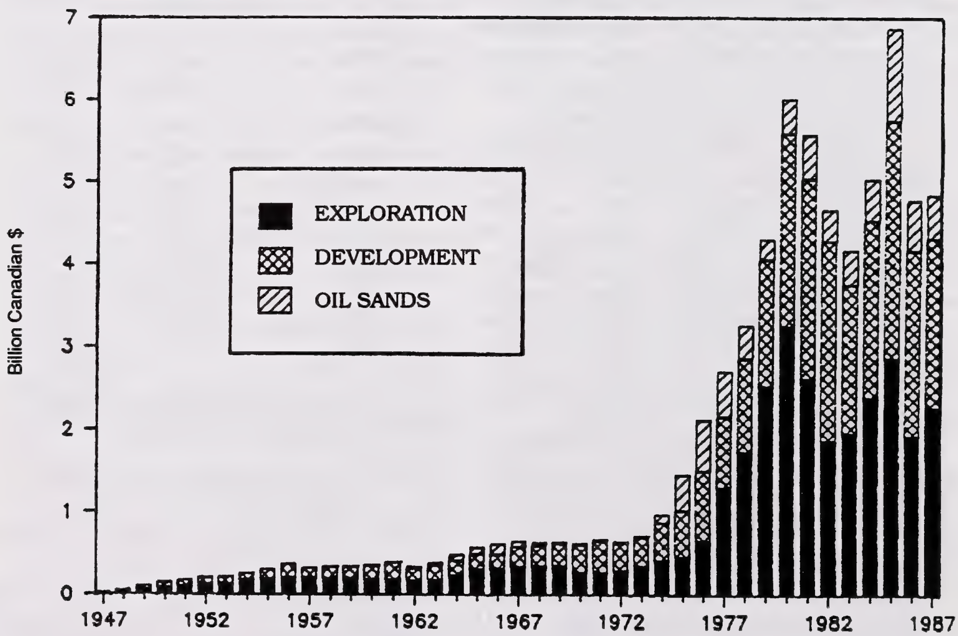
Source: Alberta Treasury, Bureau of Statistics

A good indication of the expanded activity in the oil and gas industry is investment made in exploration and development of the petroleum resources. In 1947, capital expenditure in Alberta totalled $26 million. At the

peak of industry activity in 1985, total capital expenditures reached $6.9 billion. After the crude oil price collapse in 1986, spending was cut back to $4.8 billion in 1986 and 1987. Cumulative capital and exploration expenditures by the industry from 1947 to 1987 amounted to $67.6 billion. Historical industry spending, broken down between exploration and development, is summarized in Figure 8. The direct spending by the oil and gas sector in Alberta over the past five years represented almost half of the total private expenditures, excluding housing.

A significant proportion of provincial revenues now flows directly from the oil and gas industry in the form of royalties, land bonuses, lease and licence payments, mineral taxes and provincial income taxes. In the Alberta government's 1985-86 fiscal year, provincial revenues from the oil industry totalled about $5 billion, representing 46 percent of the province's total revenue. The 1986 drop in prices for oil and natural gas had a dramatic effect on provincial revenues from the industry. In the 1986-87 fiscal year, they had dropped to about $2.5 billion. There has been a slight recovery. In 1988, government revenues from energy resources totalled $2.7 billion, about 28 percent of the government's overall revenue (Alberta Energy 1989). Projections indicate that direct provincial revenues from the oil and gas industry will probably remain at the lower level.

Figure 8. Alberta Oil and Gas Capital Expenditures



Source: Canadian Petroleum Association 1989

Chapter Seven

Managing Resources for the Future

Our Common Future, the 1987 report by the World Commission on Environment and Development (the Brundtland Commission), explored the concept of sustainable development and concluded that

> *Sustainable development is development that meets the needs of the present without compromising the ability of future generations to meet their own needs* (WCED 1987: 43).

> *The concept of sustainable development does imply limits — not absolute limits but limitations imposed by the present state of technology and social organization on environmental resources and by the ability of the biosphere to absorb the effects of human activities. But technology and social organization can be both managed and improved to make way for a new era of economic growth* (WCED 1987: 8).

The concept of sustainable development does not apply directly to oil and gas resources because, for all practical purposes, these resources are neither renewable nor sustainable over the long term. Nevertheless, in keeping with the spirit of sustainable development, it is prudent that the present generation use and manage oil and gas resources keeping in mind their non-renewable nature and the interests of future generations. Sustainable development in terms of non-renewable resources means, as Aitken has stated "Don't exploit the resources at a rate which exceeds your ability to develop another or develop a substitute product." (Aitken 1988: 4). As well, non-renewable resource development should not threaten the long-term sustainability of the host environment and the renewable resources upon which future generations depend.

Managing Alberta's oil and gas resources in this manner is not a simple matter, nor can it be done in isolation from the economic, political, social, and environmental events occurring in other parts of Canada or around the world. The following sections are intended to provide a broad overview or background of global aspects that affect the Alberta situation.

Global Background

Two fundamental characteristics of the oil and gas industry are:

1. Oil and, to a lesser extent, gas are traded extensively in world markets and consequently, consuming and producing countries are linked to a common pricing system.
2. Although oil and gas are two of the primary resources that satisfy energy demand, there are other non-renewable resources and a wide range of renewable resources that serve a similar purpose.

The global nature of oil trading results in a world-wide integration of market forces. Consequently, significant changes or even perceived changes in demand or supply in one

area may lead to virtually instantaneous changes in the price of "benchmark" crude oils. To a lesser extent, this may affect natural gas prices around the world. For example, the decision by the OPEC countries to increase their oil production in late 1985 led to the dramatic decrease in world oil prices in early 1986, with catastrophic effects on the Alberta oil industry and its economy. Similarly, rumors and perceptions of hostilities and peace initiatives in the Middle East produce significant day-to-day price changes. Because natural gas is more difficult to transport than oil, its trading patterns are less global and prices are influenced more by local supply and demand.

In the long term, our ability to use a variety of resources to satisfy energy demand can constrain price fluctuations for a specific energy resource. If demand for oil outstrips production and the world price escalates, some of the demand will be supplied by other, less expensive energy sources, or conservation actions will reduce demand. However, our ability to substitute one energy resource for another or to reduce demand through improved energy efficiencies or conservation frequently depends on the installation of suitable equipment. Consequently, short-term flexibility is limited.

Individuals, companies, and government all attempt to assess trends in energy prices in making the myriad present-day decisions. The price increases of the 1970s led some major industrial consumers to install equipment that allowed them to use a variety of fuels. As a result, some industrial and institutional consumers are able to switch between oil and gas or to coal or other energy sources in response to price changes although few can do so for a sustained period in the short term. For example, it is estimated that only 10 percent of the existing industrial gas users in Ontario and Quebec could be switched from natural gas to heavy oil in the short term (National Energy Board 1988). However, the National Energy Board estimates that "if a 30 percent price differential persisted for a longer time period, say three years ... about 20-30 percent of eastern Canadian gas consumption could be lost to other energy sources" (National Energy Board 1988: 39).

Supply, the other side of the supply-demand coin, is an equally complex variable. The availability of reserves is, by itself, insufficient to guarantee production; the slow development of Alberta's oil sands being a case in point. Production must make economic sense and the cost of producing and marketing reserves varies dramatically. Because so much of the world's reserves of conventional crude oil exists in cheap-to-produce reservoirs in the Middle East, especially in Saudi Arabia, that country and other OPEC members have a major influence on world oil prices. By altering production, they influence the price which in turn, influences demand, the search for alternative energy sources, and the development of known oil reserves.

Imposed on the typical price-demand relationship is the complicating factor of politics. In the late 1960s and early 1970s, economical and readily available supplies of oil seemed unlimited. By 1972, the OPEC nations provided almost 85 percent of all imports and 54 percent of the world's oil production (Petroleum Resources Communication Foundation n.d.). The sudden increase in oil prices in 1973 caused oil importing countries to reassess their dependence on imports and reevaluate their relationships with oil exporting countries.

The result was a general rise in the non-OPEC crude oil supply. Increased value for oil meant that the expensive technology required to develop hard-to-produce resources became more economical and the costly search for new reserves in the world's northern and offshore areas became more viable. As well, governments, corporations, and, to a lesser extent, individuals, responded with policies and actions directed toward self-sufficiency in energy supply, protection against future price increases, and reduced depend-

ence on offshore energy supplies, especially those from the OPEC nations. All of these factors, and more, combine to make predictions of demand and price for oil and gas about as accurate as reading tea leaves.

The supply of oil and gas changes as known reservoirs are depleted and new ones discovered. The Oil and Gas Journal estimated the world's oil reserves at the end of 1987 at 141 billion cubic metres (887 billion barrels) and 1987 production at 3.2 billion cubic metres (20 billion barrels). Thus, at the current rate of production, the world has sufficient conventional oil reserves to last about 44 years. Future discoveries will add to the reserve base but, to a greater or lesser extent, they will be offset by production. Conventional oil reserves will eventually begin to decline. Conventional oil will be able to satisfy a decreasing share of the world's energy demand. The world will receive its energy from sources other than conventional oil. Over a longer term, natural gas production also will decline.

The Brundtland Commission presented the following assessment of future energy supplies:

> *Many forecasts of recoverable oil reserves and resources suggest that oil production will level off by the early decades of the next century and then gradually fall during a period of reduced supplies and higher prices. Gas supplies should last over 200 years and coal about 3,000 years at present rates of use* (WCED 1987: 174).

It is not clear whether the Commission's forecast allowed for the impact of higher prices on demand or on production. If it did not, the forecast may be too conservative. An indication of the potential impact of higher prices on oil supply is conveyed in a Chevron assessment of world energy outlook (*Oil and Gas Journal* Oct. 26, 1987). The report indicates that, at prices of $160 to $250 (U.S.) per cubic metre ($26-$40 per barrel), improved technology for enhanced oil recovery could add 130 billion cubic metres (800 billion barrels) to current estimates of recoverable reserves, an amount almost as great as the present estimate of proven reserves.

The impact of high oil prices was demonstrated during the last decade. The dramatic change in prices in 1973 and particularly in 1979 contributed significantly to a world-wide economic recession and a major decrease in demand for energy resources, including oil (Figure 9). The higher prices also pushed conservation programs on a wide front, contributing to significant decreases in total energy demand. The *Oil and Gas Journal* (July 27, 1987) reported on energy consumption efficiency in the United States over the last several decades. During the 1960s, oil consumption per dollar of Gross National Product was about 12,700 *kilojoules* (12,000 BTUs) as compared with 12,130 kilojoules (11,500 BTUs) in the 1950s. By 1973, consumption had increased to 13,400 kilojoules (12,700 BTUs) but declined to about 9,000 kilojoules (8,500 BTUs) per dollar of Gross National Product by 1987. These changes broke the traditional pattern of energy consumption tracking Gross National Product. Increasing energy consumption is no longer considered an indicator of economic well-being but an indicator of inefficiency. As a result, energy use is being considered in a new light by some analysts. They are looking at the end uses for which the energy is required and how these uses can be most efficiently met instead of simply increasing traditional energy supplies in response to demand.

The net result has been a decline in world demand for oil from a peak of more than 10.3 million cubic metres (65 million barrels) per day in 1979 to slightly more than 9.4 million cubic metres (59 million barrels) per day in 1983. This had only increased to 9.9 million cubic metres (62 million barrels) per day by 1987 (Arthur Andersen and Co. 1988b). Not only did higher oil prices lead to reduced demand, they also stimulated oil exploration, leading to the discovery of new reserves, and the development of previously

Figure 9a.

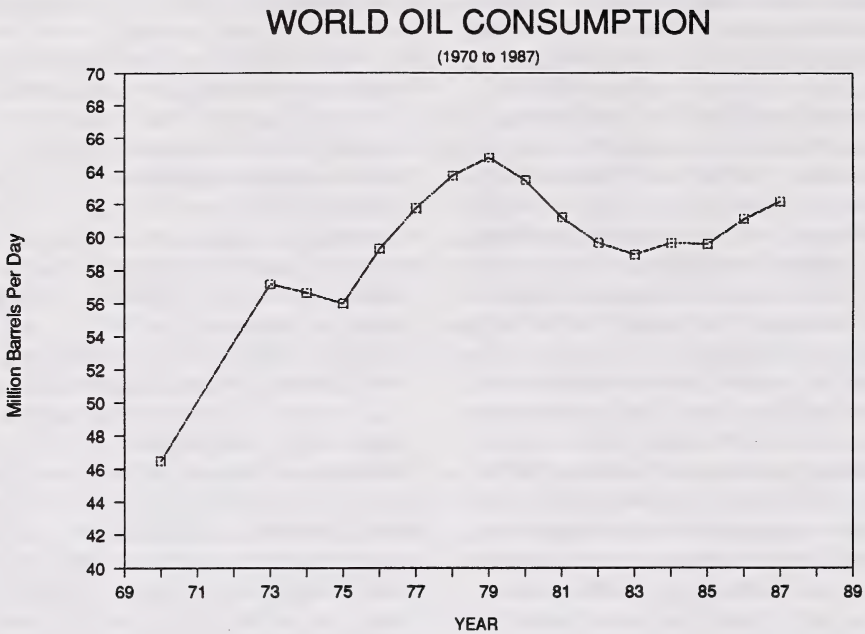
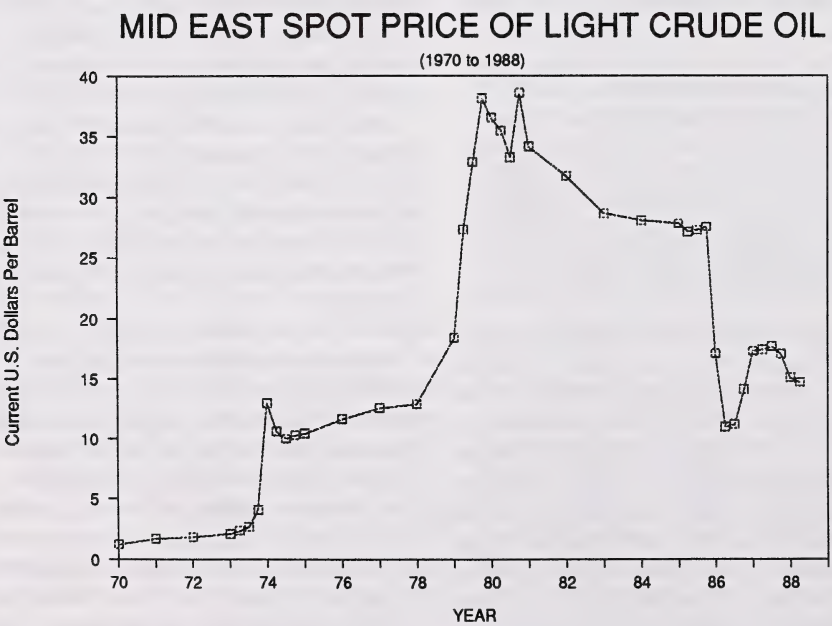


Figure 9b.



Source: Arthur Andersen and Co. 1988b

uneconomic proven reserves. In many countries, special government programs, designed to aid security of supply, increased supply capability.

The reduction in demand, coupled with the development of new oil supplies, resulted in substantial excess productive capacity and reduced prices. This excess capacity continues through to the present and is a constant threat to price stability. As long as excess productive capacity exists, there will remain little upward pressure on oil prices. The lower price for oil has also reduced the impetus of the energy conservation drive, and slowed the development of more expensive supplies of oil and of other energy sources, including renewable energy. It is unlikely that the gains in energy use efficiencies will be reversed. According to Zwicky (1988), it is less expensive, even at today's prices, to conserve energy than to develop additional sources. Furthermore, new technologies are being marketed that are even more energy efficient. Increased demand may come mainly from the developing nations. Per capita energy use in developing countries is less than one sixth of that in the rich industrialized nations. And most developing countries are experiencing rapid increases in population. Yet even in those countries, some forecasters suggest that the growth in energy demand could be drastically lower than conventional projections would indicate if modern energy technologies are used in high-efficiency applications (Goldemberg et al 1987).

Eventually, demand will catch up to the productive capacity. However, given the large oil reserves in the Middle East and the low cost of producing those reserves in the foreseeable future, oil prices will continue to be dominated by the production rates of the middle eastern countries. It would seem to be in the long-term economic interest of these countries to maintain oil at a price that is low enough to encourage use, but not high enough to encourage energy conservation or development of the more costly energy supplies that exist in other countries. As reserves elsewhere in the world are depleted over the next couple of decades, oil prices could increase or the Middle East could develop and market its plentiful reserves of natural gas. The future pricing of energy resources, however, depends as much on the politics of energy supply and demand as it does on fundamental statistics of energy reserves.

Alberta Background

Alberta's primary non-renewable energy reserves can be categorized as follows:

1. Conventional oil — declining supply capability with only limited production in less than 35 years.
2. Bitumen — enormous reserves which, under conditions of high oil prices, could supply synthetic crude oil for hundreds of years depending on the rate of depletion. Potential bitumen reserves are equivalent, on a volume basis, to about 30 percent of the world's current oil reserves. Figure 4 showed how the decline in conventional oil production is expected to be offset by production from oil sands reserves.
3. Gas — increasing supply capability for about 10 years followed by declining capability.
4. Coal — enormous reserves that could be used directly as a fuel source or could be used as a feedstock to produce gas or liquid products comparable to petroleum products, if energy prices increased enough to justify this action.

It is also important to note that Alberta's energy requirements represent only about 26 percent of the total production (Table 5). Most of Alberta's hydrocarbon production, especially oil and gas, is sold to the rest of Canada or exported. These sales are critical to the provincial economy and to a large degree drive

Table 5. Distribution of Alberta's Energy Resources, 1988 Production (in petajoules)

	Alberta Requirements	Exported to Other Areas	Total
Conventional Oil and Equivalent	710	2,475	3,185
Gas	700	2,500	3,200
Coal	420	220	640
TOTAL	**1,830**	**5,195**	**7,025**

Source: ERCB 1988a

present Alberta oil and gas development strategies. Devising a conservation strategy must, as a first step, address the questions of how much and how fast should Alberta's energy resources be developed and exported and what are the environmental and social implications of this development? This, in turn, relates to the desired economic future for Alberta and the economic contribution from other sectors of the economy. As the government has recognized, diversification is the only means by which Alberta can reduce its dependence on oil and gas revenues and become free to manage its non-renewable resources in support of a long-term sustainable economy and not for short-term economic growth and revenues.

In the next century, world oil supply capability is expected to peak and begin to decline. Oil prices can be expected to increase significantly. Experience has shown that reactions to the higher prices will include the following:

1. Total energy demand will be reduced.
2. Where economically attractive, oil will be replaced by other energy resources including renewables.
3. Consumers will increase oil use efficiency.
4. New oil supplies will become available through more efficient enhanced recovery operations and the development of high-cost non-conventional sources such as oil shales and oil sands.

Alberta's oil sands reserves are so immense that high oil prices could lead to almost any level of long-term oil production. To illustrate — Alberta had an oil supply capacity of about 230,000 cubic metres (1.5 million barrels) per day for much of the last decade with virtually all of it supplied by conventional oil. If all of that supply had to come from oil sands reserves, it could be sustained for several hundred years.

Present forecasts are for conventional oil production to decline to 15,400 cubic metres (100,000 barrels per day) by 2025. To match Alberta's past oil production of 230,000 cubic metres per day solely with production from the oil sands would require about 10 plants of the same capacity as the present Syncrude operations to be built within the next 35 years.

This scenario is extreme because heavy oil developments are also expected to provide much of the needed oil supplies. Nevertheless, the real question is not the extent of

bitumen reserves but what are the environmental, social, and economic costs of these high rates of production? And are they acceptable? Does the level of development in the oil sands fit with the view Albertans have for the future of their province? Is it necessary or desirable?

Fortunately, extensive environmental research and monitoring has been carried out in the surface mining area near Fort McMurray. The cumulative impact of plant emissions from the two oil sands plants in the surrounding area has been measured over the last decade. The impact of operations on wildlife has also been assessed by regular monitoring surveys. As a result, the data base is good and provides a basis for assessing the impact of further developments. However, no thorough assessment has been done of the cumulative impacts of the level of development required to offset declining reserves of conventional oil.

While current operations have created social, economic and environmental problems for the local community, many of these appear to be moving toward resolution. However, it is clear that further developments in the area need to be planned very carefully with regard for both environmental and socioeconomic impacts.

Similarly, heavy oil developments on the scale needed to offset conventional oil production also will be accompanied by environmental and social costs as discussed in the earlier section.

The likelihood of the variety of alternative developments — enhanced recovery, heavy oil extraction, and oil sands mining or *in situ* extraction — depends on the price for oil and gas, and on the level of government financial assistance. There is little Alberta can do to affect global energy prices, supply, or demand. The negative impacts of the global recession and low oil prices were apparent in Alberta despite provincial attempts to offset them. Oil prices were low because the capacity to supply world oil markets greatly exceeded demand. Government support programs kept oil and gas exploration and development activity at a level higher than it would have been in the absence of these programs. But these programs could not develop the necessary markets for the petroleum products that would support further development. New reserves, especially of natural gas, had to be shut in because of excess production capability. Production capacity still exceeds demand and is predicted to do so for the next two years even with increased sales to the United States (National Energy Board 1988).

At a national level, the greatest change in the energy future may come from the impact of the Free Trade Agreement. The energy portion of the Agreement is a continuation of the deregulation of oil and gas marketing to allow freer access by Canada and the United States to each other's energy markets. The Free Trade Agreement should allow improved access to markets in the United States. If Alberta's share of the United States' market does increase, the growth in oil and gas development activity in Alberta would stimulate the economy, benefitting the province's oil and gas industry and the economic wellbeing of Albertans.

But one must question the long-term benefit to Albertans of increased export of oil and gas. Alberta's conventional oil production is already diminishing and natural gas production is projected to peak in the next decade. Sources of supply to replace diminishing reserves will be more expensive to develop and produce than present supplies. If world oil prices do not increase sufficiently to make the development of new supplies economical, government support may be needed. The necessity of financial backing by the provincial and federal governments for the heavy oil upgrader and the third oil sands plant (as well as offshore developments) indicates that present oil prices do not provide the necessary return on investment to stimulate private enterprise to construct these facilities. It may not be sensible for governments to support the development of

these energy sources while at the same time encouraging increased exports of our lower-cost existing reserves. The end result could be more expensive energy in the future, perhaps placing Alberta at a competitive disadvantage with other suppliers of oil and gas. Providing oil and gas to market at less than their 'true' cost also encourages continued inefficiency in energy use.

World supplies of conventional oil are sufficient for approximately 45 years and natural gas reserves sufficient for about 200 years, much of it available at lower cost than oil from new oil sands plants or heavy oil upgraders. The OPEC countries, which control about 75 percent of the world's oil reserves (Arthur Andersen and Co. 1988b) as well as about one-third of the world's supply of natural gas (Arthur Andersen and Co. 1988a) may be able to keep the world price of oil below the cost of profitable production from bitumen for many years. As reserves of oil and gas in other parts of the world are depleted, the OPEC producers would increase prices enough to make synthetic crude oil production profitable. But this might not happen for many years. Uncertainty about future oil prices continues to make private industry reluctant to commit itself to new megaprojects.

If Alberta can do little to influence trends in oil and gas consumption, the best course of action may be to anticipate and respond to the trends. If the trend continues toward slower global growth in energy use, improved efficiency in energy use, and a shift away from oil, energy prices may stay low for longer than anticipated. Under this scenario, megaprojects might prove uneconomic for longer than planned and perhaps should be discouraged in favor of incremental expansion of existing production capabilities. Increased production of Alberta's conventional oil and gas should perhaps be slowed, awaiting rising prices, instead of increased to supply export markets at present low prices.

The key to the development of Alberta's bitumen reserves is price. Oil prices must rise (and show promise of stability at the higher levels) to make new oil sands or heavy oil plants economical. But, as discussed earlier, price increases reduce demand and stimulate the development and use of alternatives. It is therefore impossible to predict the level of development of Alberta's bitumen.

The availability of non-renewable energy sources would be extended further if the community of nations adopted the kind of environmental standards or controls recommended by the Brundtland Commission. In its 1987 report, the Commission discussed the potential environmental impacts of increasing consumption of fossil fuels. It proposed the following four-track strategy for addressing the complexities and uncertainties surrounding the issue of global climate change:

— *Improved monitoring and assessment of the evolving phenomena.*

— *Increased research to improve knowledge about the origins, mechanisms and effects of the phenomena.*

— *Development of internationally agreed-upon policies for the reduction of the causative gases.*

— *Adoption of strategies to minimize damage and cope with the climatic changes and rising sea levels* (WCED 1987: 176).

Over the next several years, if the realities of climatic change become more demonstrable, governments around the world may pass legislation to reduce the use of fossil fuels or emissions of carbon dioxide. They have already agreed to take action to reduce nitrous oxide emissions. Shifting energy sources from coal, synthetic oils, and, to a lesser extent, conventional oil to greater use of natural gas has been suggested as a possible interim action. Natural gas produces less carbon dioxide per unit of energy released than the other fossil fuels. Coal and bitumen have higher carbon to hydrogen ratios and

thus produce more carbon dioxide per unit of energy released. But as discussed earlier, recent data show that carbon dioxide is released during the extraction of gas and during the processing of natural gas for use (Burn 1989). Likewise, considerable energy is required to convert bitumen into usable refined petroleum products. The desirability and consequences of fuel shifting require careful scrutiny and public discussion.

Actions in Canada and in other countries could have drastic implications for the future use and export of Alberta's energy resources. The Alberta Conservation Strategy must address these issues.

Chapter Eight

Toward an Energy Strategy

For the foreseeable future, Alberta will have no shortage of energy resources in general, and oil and gas resources in particular. An abundance of energy sources is not enough, however.

Development of Alberta's oil and gas resources will ultimately depend on economic returns. The economics of energy supply and demand is critical. If the price of world oil increases slowly and steadily, the transition from less expensive energy supplies to more expensive ones, improvements in efficiency of use, and shifts from one energy source to another may also be gradual.

OPEC countries are still producing oil substantially below their capacity and the price of oil is determined by manipulating production rates rather than by a balance of supply and demand. Based on past experience, Alberta's economy, dependent to a large degree on the direct and indirect benefits of fossil fuel exploitation, may look forward to ups and downs. Both federal and provincial governments have attempted to buffer economies from the impacts of energy price changes. Incentives for exploration, royalty tax relief, government loans and guarantees, diversification of the economic base, fuel substitution programs and development of alternatives have all been tried. Most of these programs have had little success in protecting local economies from the influence of world energy prices. This will likely remain the case because Canada is a relatively small player in world energy markets and thus cannot march out of step with the major players for long.

How do we prepare an oil and gas strategy under these conditions? Should the emphasis be on diversification of the provincial economy to reduce its dependence on the income from oil and gas development, or on diversification of energy sources and markets? Both are happening. Oil and gas revenues now make up a much smaller portion of provincial revenues than 10 years ago. Energy use efficiencies have been improved and Canada has substantially reduced the proportion of oil used as a primary energy source. Is this enough? How much more effort should be placed on diversification of the economy and energy developments?

It is unlikely that Albertans will run out of energy sources. Alberta is in the enviable position of having access to a variety of both renewable and non-renewable energy sources. The reserves in the oil sands and heavy oil areas are so immense that they will be available for many generations although future supplies of oil and gas will be more expensive to develop than those used today. The questions to be addressed in an oil and gas strategy are: when, how, and how much. When and how should different energy options be implemented? How should decisions be made? How much will it cost (in both economic and environmental terms) to pursue different options?

One of the objectives of the draft Alberta Conservation Strategy is "to use and manage our non-renewable resources in the interests of developing a long-term sustainable economy for Albertans." Present oil and gas developments should provide for the future. They should ensure that future generations

have access to competitively-priced energy sources and that our use of non-renewable resources will incur no debts, economic or environmental, for the future.

Does this mean that we should leave our oil and gas resources in the ground for the next generation? That is one possible action; ensure that sufficient reserves are in place before export of resources is permitted. This would be a reversal of the current trend that has seen a loosening of restrictions on exports, particularly of natural gas. But is it a desirable trend?

There are other actions to consider, for example:

- Improve recovery rates of known reserves.
- Develop alternative energy sources.
- Promote energy conservation and energy-efficient lifestyle changes.
- Increase support for research and development.
- Institute a 'carbon tax' on fossil fuels.

Development of cost-effective technologies that improve the recovery rate of oil reserves is one method that might accomplish the same end — to leave resources for the future. Development of alternative energy sources, both renewable and non-renewable, is another. Energy conservation is yet another. One practical step might be to divert a portion of present oil and gas income into research and development technologies that achieve the actions stated above. These actions would all help progress toward the objective of ensuring that our oil and gas resources are managed in the interest of the present generation as well as future generations. In most cases, it is not a matter of one action or another, but of developing a long-term strategy that considers these and many other possible options. Which ones should receive priority?

Given the large reserves of both oil and gas in other parts of the world, it is important that Alberta keep the long-term cost of its energy sources competitive. Investment in research and development that helps to increase resource recovery rates, reduce energy use, improve the cost effectiveness of alternatives and develop new, less-expensive technologies, are all actions that would help Alberta maintain its competitive position. The technology developed may itself form the basis for new industries in Alberta. Are these actions desirable or should Alberta invest oil and gas income in increasing present exploration or production facilities?

An oil and gas strategy also should ensure that future generations are not burdened with the environmental debt of today's actions — a legacy of environmental problems. The discussion papers for the Alberta Conservation Strategy project have dealt with the importance of natural resources to the economic and social well-being of the province. In most cases, the activities of one sector have linkages to other sectors and to the natural resource base of the province. Oil and gas development affects air and water quality, fish and wildlife, and land uses including forestry, agriculture, tourism, and so on. These effects may be beneficial or detrimental, but it is important that as much effort as practical be spent on minimizing any long-lasting negative effects on the environment. These effects could have a negative impact on the future of the oil and gas industry and on other users of Alberta's natural resources.

Environmental as well as economic values must be incorporated into all aspects of energy policy. The aim should be to minimize the negative impacts. Great strides have been made to develop processes to help solve or avoid problems and find a better way of doing business. The oil and gas industry has made co-operative efforts in this regard and has shown a greater appreciation of the concerns of other interests. In addition, legislation has restricted certain activities and led to the development of environmental standards and guidelines. Overall, the environmen-

tal impacts of oil and gas development have been substantially reduced. Although industry can be commended, oil and gas development remains a matter of major environmental concern in Alberta.

Several important environmental issues remain to be addressed: the impact of development on tourism and recreation potential, the social and environmental implications of extensive oil sands development, and the implications of concern about the contribution of fossil fuel use to "climate change" and other atmospheric changes.

Oil and gas development remains one of the most important environmental issues in Alberta. It unavoidably disturbs the land surface and removes land from other uses for varying periods. Oil and gas development affects every other use of the land surface: agriculture, forestry, transportation, urban development, recreation, fish and wildlife habitat, and so on. The concern is especially evident in discussions about the protection of public lands that have high value for fish and wildlife habitat, recreation, and tourism. If tourism is to be Alberta's industry of the future, then petroleum development must not harm the habitat and aesthetic resources that the industry depends on.

If the ERCB's projections are correct, then massive development of the oil sands will be essential within the next couple of decades. This has important environmental implications. Development of oil sands is land-use intensive, energy-intensive, and concentrated in a relatively small area of the province. Do we know enough about the cumulative environmental and social consequences of the shift from conventional oil supplies to synthetic oil? Do we have appropriate mechanisms to deal with concerns and develop progressive solutions to future problems? These matters could be addressed in an oil and gas strategy.

Public concern about climate change is growing. Fossil fuel use is regarded as a major contributor to climate change and other atmospheric problems such as urban smog and acid rain. Canada is already party to agreements aimed at reducing emissions of sulphur dioxide and nitrogen oxides. Policies aimed at reducing carbon dioxide emissions are inevitable. What options are available to Alberta? How much might we be affected by policy decisions made outside Alberta concerning use of fossil fuels? What might be the consequences of these actions for natural gas and synthetic oil development?

Albertans are faced with some tough decisions about their energy future and the place of fossil fuels in that future.

- What emphasis should be given to improving efficiencies of energy use?
- Should some energy sources be given preferential treatment?
- What level of export of fossil fuels is desirable and for how long?
- Are Alberta's heavy oil and oil sands reserves able to provide oil that is competitive at world oil prices?
- Is it desirable, on the basis of social goals, for these currently uneconomic energy developments to be subsidized?
- Have local and global environmental imports been adequately considered in our energy policies?

To address these questions adequately requires not only technical information about potential reserves and production rates but also value judgements. Social, environmental, health, and economic considerations all are very important in making decisions about how Alberta should manage its non-renewable resources in the interests of developing a sustainable economy.

Increasing prices for petroleum products and natural gas can be expected to affect demand for energy in Alberta as well as development of energy supplies. In general terms, renewable resources such as solar, wind and biomass will become more important and oil and gas less important. However,

Alberta's large bitumen and coal reserves may mean a limited role for renewable resources in meeting future energy demands in the province. Conversely, growing concern about global climate change may result in much greater emphasis on the development of renewable energy sources. The future depends as much on policy responses to environmental concerns as it does on the availability and cost of developing energy supplies.

There will always be marginal energy alternatives awaiting higher energy prices. Today, it is heavy oil and oil sands; tomorrow, it will be renewable energy sources, tertiary recovery technologies, exploitation of deeper oil sands reserves, and gasification or liquification of coal. Development of these reserves can be encouraged through economic assistance. An alternative is to encourage energy conservation. The non-renewable resources conserved could be sold to increase provincial revenues or saved for the future. How Albertans wish to develop their energy resources is a matter that deserves very serious discussion. There are, of course, enormous uncertainties in attempting to plan for the future. Technological developments have a major impact on the supply capability of any resource — renewable or non-renewable. Changes in public policy can also have major impacts.

But appropriate mechanisms or institutions need to be in place for involving government, industry, and the public in making the necessary decisions. Both industry and the ERCB have the modelling and analytical skills necessary to forecast energy supply and demand. But these skills have not been combined with public debate to develop long-term energy policies, nor to address the social and environmental implications of such policies. That is not the mandate of the ERCB. Its mandate is to ensure that the province's energy resources are developed efficiently to supply projected needs.

A process is needed to convert Alberta's wishes and aspirations for the future into a comprehensive energy policy. What is that mechanism to be?

The development of the Alberta Conservation Strategy should provide direction for such mechanisms. Important in these considerations will be our ability to look at all sides of the matter before arriving at a consensus on a course of action. In keeping with the objective of the Alberta Conservation Strategy, development of Alberta's energy resources should be conducted in the interest of long-term sustainable economy for Albertans — an economy that is environmentally sound and recognizes the needs and aspirations of future generations.

Planning for this future should begin now.

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Glossary

Bitumen: A naturally occurring viscous mixture of hydrocarbons that, in its natural state, is not recoverable at a commercial ratio through a well.

Condensate: A mixture of pentanes and heavier hydrocarbons that are produced with natural gas. It is gaseous in its virgin state but at least some of these hydrocarbons condense to a liquid when brought to the surface. It is separated from the gas by cooling and various other means.

Conventional Crude Oil: Oil which can be recovered through a well at a commercial ratio.

Crude Oil: Oil as it comes from the well. Unrefined liquid petroleum.

Established Recoverable Reserves or Established Reserves: Those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing and production, plus that judgement portion of contiguous recoverable reserves that are interpreted to exist, from geological, geophysical or similar information, with reasonable certainty.

Heavy Oil or Heavy Crude Oil: Crude oil with a density of 900 kilograms or more per cubic metre. It is a thick, sticky, viscous, form of crude oil.

Heavy Oil Upgrading: The conversion of heavy oil into light or medium oils by a combination of hydrogen addition or carbon removal.

Hydrocarbons: Organic chemical compounds consisting of hydrogen and carbon atoms which form the basis of all petroleum products.

In Situ: Literally meaning "in place". Used in reference to extraction of oil from oil sands, the term refers to processes used to make bitumen less viscous and, therefore, possible to extract through a well.

Initial Established Reserves: Established reserves prior to the deduction of any production.

Joule: The basic unit of energy in the metric measurement system. It is defined as the work done when the point of application of a force of one newton is displaced a distance of one metre in the direction of the force.

Light and Medium Crude Oil: Generally crude oil with a density of less than 900 kilograms per cubic metre.

Oil Sands: Sand, clay and other rock material which contain crude bitumen buried in layers of various thickness.

Pentane: A hydrocarbon having five carbon atoms in the molecule, occurring as a liquid in natural gas or crude oil.

Pentanes Plus: A mixture mainly of pentanes and heavier hydrocarbons which ordinarily may contain some butanes and which is obtained from the processing of raw gas, condensate, or crude oil.

Remaining Established Reserves: Initial established reserves less cumulative production.

Synthetic Crude Oil: Crude oil produced by upgrading bitumen. Synthetic crude oil is a high quality feedstock for conventional crude oil refineries.

Ultimate Potential Reserves: Ultimate potential includes cumulative production, remaining established reserves and future additions to reserves through extensions and revisions to existing pools and the discovery of new pools.

Viscosity: The ability of a liquid to flow. The lower the viscosity, the more easily the liquid will flow.

UNITS OF MEASUREMENT

1 cubic metre of oil is equivalent to 6.3 barrels.

1 cubic metre of gas is equivalent to 35.3 cubic feet.

Megatonne: One million tonnes.

Kilojoule: One thousand joules.

Petajoule: 10^{15} joules (one quadrillion joules).

Appendix A

Members of the Energy and Non-Renewable Resources Sub-Committee

This paper began as a project under the auspices of the Energy Sub-Committee in early 1986. In late 1986, this group merged with the Non-Renewable Resources Sub-Committee, which assumed responsibility for the paper. Listed below are those persons who served on the Energy Sub-Committee and the Energy and Non-Renewable Resources Sub-Committee at some time during the preparation of this paper.

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Appendix A

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About Our Logo

ENVIRONMENT COUNCIL OF ALBERTA

Over the past two decades, the logo of the Environment Council of Alberta has shown three overlapping triangles as representing the foundations of our environment: land, air, and water. These triangles also represent the three groups with which the ECA interacts: industry, government, and the public. The three triangles intersect to form a circle symbolizing the biosphere. The small triangle in the centre of the circle symbolizes these three groups joining together to work for the conservation of our environment.

In 1980, the overlapped triangle motif was used by the World Conservation Strategy to represent the three primary objectives of that document. The Alberta Conservation Strategy incorporated the triangle motif into its logo by overlaying the WCS triangles onto a three dimensional outline of Alberta. This combination of triangles with the readily identifiable outline of provinces, nations, and regions has marked conservation strategies around the world.